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NO_X COMBUSTION CONTROL METHODS AND COSTS FOR STATIONARY SOURCES.

SUMMARY STUDY

ACUREX CORPORATION

PREPARED FOR
INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY

SEPTEMBER 1975

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The report summarizes the technology, user experience, and cost for NOx control from stationary combustion sources. It characterizes significant sources by equipment type, fuel consumption, and annual mass emission of NOx. It summarizes NOx control technology by combustion modification, fuel modification, flue gas treatment, and use of alternate processes. It identifies combustion modifications as the most advanced and effective technique for near- and far-term NOx control. It gives available capital and differential operating costs for NOx control in utility boilers by combustion modification and flue gas treatment. Combustion control of NOx is an order of magnitude lower in capital cost than NOx or SOx control by flue gas treatment. Cost data for remaining equipment types is sparse and the need is cited for open dissemination on a standardized basis of data on field tests of NOx control techniques.

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NO_x COMBUSTION CONTROL METHODS AND COSTS FOR STATIONARY SOURCES

Summary Study

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ABSTRACT

This report summarizes the technology, user experience and cost for NO_x control from stationary combustion sources. The significant sources are characterized by equipment type, fuel consumption and annual mass emission of NO_x. Stationary sources emit 11.7×10^6 TPY (1972) of which 98% is due to fuel combustion ranked as follows: coal, 37%; gas, 36%; oil, 25%. The most significant source sector is utility boilers with 49% of stationary emissions. The technology for NO_x control by combustion modification, fuel modification, flue gas treatment and use of alternate processes is summarized. Combustion modifications are identified as the most advanced and effective technique for near and far term NO_x control. Available capital and differential operating costs are given for NO_x control in utility boilers by combustion modification and flue gas treatment. NO_x control by combustion is an order of magnitude lower in capital cost than NO_x or SO_x control by flue gas treatment. Cost data for remaining equipment types is sparse and the need is cited for the open dissemination on a standardized basis of data on field tests of NO_x control techniques.

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SECTION I

INTRODUCTION

Oxides of nitrogen (NO_x) are currently emitted at a rate in excess of 20 million tons per year. Over 98 percent of man-made NO_x emissions result from fuel combustion with the majority due to stationary sources. Combustion generated oxides of nitrogen are emitted predominantly as nitric oxide, NO, a relatively harmless gas, but one which is rapidly converted in the atmosphere to the toxic nitrogen dioxide, NO_2. NO_2 is deleterious to human respiratory functions and, with sustained exposure, can promote an increased incidence of respiratory ailments. Additionally, NO_2 is an important constituent in the chemistry of photochemical smog. The NO/NO_2 conversion in the atmosphere promotes the formation of the oxidant ozone, O_3, which subsequently combines with airborne hydrocarbons to form the irritant peroxyacylnitrates (PAN). NO_2 is also a precursor in the formation of nitrate aerosols, the health effects of which are under study by the EPA.

Under provisions of the 1970 Clean Air Act, the Environmental Protection Agency promulgated a National Ambient Air Quality Standard for NO_2 of $100 \mu gm/m^3$ annual average. To achieve and maintain this standard, the Clean Air Act mandated a 90 percent reduction in mobile source emissions and, for stationary sources, provided for standards of performance for new stationary sources and state implementation plans or local regulations for new or existing sources. Standards of performance for new sources have been promulgated as follows:

	Gas	Oil	Coal
Steam generators > 250 x 10^6Btu/hr	0.2 lb/10^6Btu (~160 ppm)	0.3 lb/10^6Btu (~225 ppm)	0.7 lb/10^6Btu (~500 ppm)
Nitric Acid Plants	3 lb NO_2/ton acid		

Standards of performance for stationary gas turbine and stationary internal combustion engines are in preparation and may be promulgated in 1975. Work on definition of a standard for intermediate sized industrial boilers is expected to begin in late 1975. The most stringent local standards are in effect in Los Angeles County as follows:

New Steam Generators:	140 lb NO_2/hr
Existing Steam Generators (>1775 x 10^6 Btu/hr):	125 ppm (gas)

Stationary source NO_x emissions can be controlled, in principal, through fuel modification, flue gas treatment, modification of operating conditions, or use of alternate processes. NO_x formation is kinetically rate controlled and, as opposed to SO_x formation, is dominated by combustion conditions. Accordingly, combustion modification has proven to be the most effective and readily implemented short and long term technique for NO_x control. The basis of combustion modification is to alleviate conditions in the primary flame zone which are favorable to NO_x formation. Control development is therefore closely related to specific equipment/fuel types. By contrast, SO_x emissions are largely dependent on fuel sulfur content and are relatively insensitive to combustion conditions, and thus SO_x control development has focused on flue gas treatment.

NO_x control techniques were initially developed for the major point sources, utility and large industrial boilers, beginning with gas and oil fired units and with subsequent treatment of coal fired units. Current emphasis is on development of combined, advanced controls for new and existing large boilers, and on generation of low NO_x design concepts for area sources such as small industrial boilers and commercial and residential heating systems. The available control technology is currently being extensively applied to retrofit of existing field units and design of new units. In light of user experience, there is currently a need to compile and disseminate results on NO_x control methods and costs.

The objective of this study is to summarize the status of stationary source combustion control technology with emphasis on control costs. This was accomplished through compilation and standardization of data from control system users and from EPA-funded contracts. Section 2 characterizes stationary NO_x sources, emission rates and fuel consumption both by major application sector and by individual equipment types. The available NO_x control techniques are reviewed in Section 3. Evaluations of control effectiveness and limitations are made for techniques which have been extensively tested. Cost data corresponding to the major control techniques are summarized in Section 4. SO_x control cost data for comparable equipment types are summarized for comparison.

The corresponding cost-effectiveness of each control technique is not explicitly treated. At this time, such an analysis would not be meaningful due to the wide range of effectiveness of a given control technique even on identical equipment types.

SECTION 2

CHARACTERIZATION OF NO_x EMISSIONS AND FUEL USAGE FOR STATIONARY SOURCES

This section presents a summary of the most recent stationary source uncontrolled NO_x emission estimates and associated emission factors for 137 major equipment/fuel combinations in the U.S. Equipment categories are separated by application sector (e.g., industrial boilers, space heaters) and by fuels. In addition, NO_x emission trends for the years 1940 - 1972 and projections to the year 1990 are discussed.

Emission estimates by application sectors are presented in Section 2.1, national summaries follow in Section 2.2. NO_x emission trends and projections are presented in Section 2.3.

2.1 1972 NO_x EMISSION ESTIMATES, EMISSION FACTORS, AND FUEL USAGE BY APPLICATION SECTOR

A comprehensive survey of 1972 NO_x emission estimates from stationary sources has recently been completed by Aerotherm (Reference 2-1) which updates and expands upon the previous inventories of ESSO (Reference 2-2), EPA (Reference 2-3), and The National Academy of Sciences (Reference 2-4). The present inventory includes 137 individual equipment type/fuel combinations from eight separate application sectors.

An overview of stationary sources of NO_x emissions is provided in Figure 2-1. The first division is by application and the second by sector. To illustrate the scope of stationary sources, the sector column has been more thoroughly detailed. These six applications encompass all major sources and the cited sectors include all those of importance within each sector. Steam generation is by far the largest application on a capacity basis for both utility and industrial equipment while space heating is the largest application by number of installations. Internal combustion engines (both reciprocating and gas turbines) in the petroleum and related products industries have generally been limited to pipeline pumping and gas compressor applications. Process heating data are not readily available, but the main source appears to be fluid catalytic crackers in the petroleum refineries and the drying and curing ovens in the broad-ranging ceramics industry. Incineration by

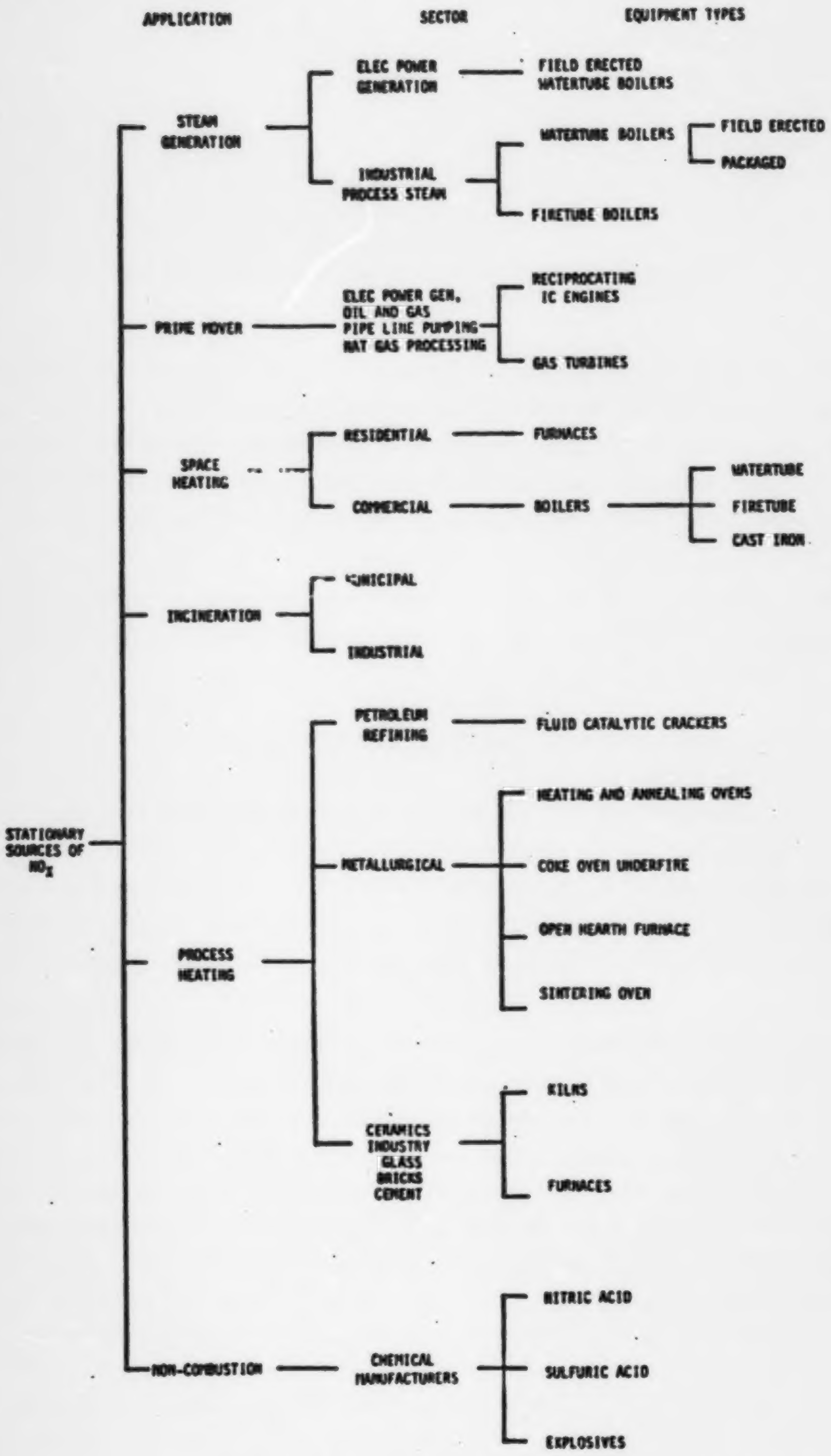

APPLICATION
SECTOR
EQUIPMENT TYPES
STATIONARY SOURCES OF NO_x
STEAM GENERATION
ELEC POWER GENERATION
FIELD ERECTED WATERTUBE BOILERS
INDUSTRIAL PROCESS STEAM
WATERTUBE BOILERS
FIELD ERECTED
PACKAGED
FIRETUBE BOILERS
PRIME MOVER
ELEC POWER GEN, OIL AND GAS PIPE LINE PUMPING NAT GAS PROCESSING
RECIPROCATING IC ENGINES
GAS TURBINES
SPACE HEATING
RESIDENTIAL
FURNACES
COMMERCIAL
BOILERS
WATERTUBE
FIRETUBE
CAST IRON
INCINERATION
MUNICIPAL
INDUSTRIAL
PROCESS HEATING
PETROLEUM REFINING
FLUID CATALYTIC CRACKERS
METALLURGICAL
HEATING AND ANNEALING OVENS
COKE OVEN UNDERFIRE
OPEN HEARTH FURNACE
SINTERING OVEN
CERAMICS INDUSTRY GLASS BRICKS CEMENT
KILNS
FURNACES
NON-COMBUSTION
CHEMICAL MANUFACTURERS
NITRIC ACID
SULFURIC ACID
EXPLOSIVES

Figure 2-1. Stationary sources of NO_x Emissions

both the municipal and industrial sectors is a small but noticeable source, primarily in urban areas. Noncombustion sources remain largely within the area of chemical manufacture, more specifically nitric and sulfuric acids and explosives.

The equipment types of greatest importance are shown next. While these equipment categories do not include all the possible variations or hybrid units, the bulk of the equipment is included in the breakdown.

Emission and fuel consumption* estimates for each application as shown in Figure 2-1 are presented in the following order:

	Table
• Utility Boilers	2-1
• Industrial Boilers	2-2
• Commercial Steam Space Heating	2-3
• Residential Space Heating	2-4
• Internal Combustion Engines	2-5
• Process Heating	2-6
• Incineration	2-7
• Noncombustion	2-8

Steam generation is separated into its two major components, electric power utility boilers and industrial process steam boilers, by virtue of the distinct differences in the two equipment types and the previous division in technology efforts. The space heating application has been divided into commercial steam units and residential heating units for obvious reasons of equipment differences.

Although NO_x control strategies are developed around a multitude of variables, the total annual NO_x emissions of each equipment type play an important role. A numerical ranking by annual NO_x production for all of the above equipment types is presented in the appendix.

---

*Nominal heating values were assumed
Coal - 12,000 Btu/lb coal
Oil - 140,000 Btu/gal oil
Gas - 1,000 Btu/scf gas
Conversion of emission factors to fuel units given lb $NO_x/10^6$ Btu to obtain:
lb NO_2/ton coal multiply by 24
lb $NO_2/10^3$ gal oil multiply by 140
lb $NO_2/10^6$ scf gas multiply by 1,000
All NO_x emissions are calculated on an NO_2 basis, i.e., a molecular weight of 46.

Table 2-1. SUMMARY OF EMISSIONS, EMISSION FACTORS, AND FUEL USAGE BY EQUIPMENT CATEGORIES FOR STEAM GENERATION – UTILITY BOILERS

Equipment Type	Firing Type	Fuel	Fuel Type[a]	NO_x 10^6 TPY[b]	LB $NO_x/10^6$ Btu[c] Emission Factor	Fuel Usage 10^{12} Btu/Yr	Numerical Ranking
Field Erected Watertube Boilers	Tangential Firing	Coal	Bituminous	1.388	0.75	3702	2
			Lignite	0.014	0.75	37.3	78
		Oil	Distillate	0.007	0.357	41.3	99
			Residual	0.177	0.357	992.1	15
		Gas	–	0.153	0.3	1021	19
	Horizontally Opposed Wall Firing	Coal, Dry Bottom	Bituminous	0.412	0.75	1099	5
			Lignite	0.004	0.75	10.7	108
		Coal, Wet Bottom	Bituminous	0.306	1.25	490	10
			Lignite	0.009	1.25	14.4	76
		Oil	Distillate	0.011	0.75	30.2	81
			Residual	0.271	0.75	723.5	11
		Gas	–	0.568	0.70	1622	4
	Front Wall Firing	Coal, Dry Bottom	Bituminous	0.412	0.75	1099	6
			Lignite	0.004	0.75	10.7	110
		Coal, Wet Bottom	Bituminous	0.302	1.25	483	10
			Lignite	0.008	1.25	12.8	96
		Oil	Distillate	0.011	0.75	30.2	82
			Residual	0.271	0.75	723.5	12
		Gas	–	0.393	0.70	1123	7
	Vertical Firing	Coal, Dry Bottom	Anthracite	0.010	0.75	26.7	85
			Bituminous	0.127	0.75	338.7	22
			Lignite	0.001	0.75	2.67	128
	Cyclone	Coal, Wet Bottom	Bituminous	0.730	1.60	912.5	3
			Lignite	0.009	1.60	11.3	89
		Oil	Distillate	0.001	0.75	2.67	129
			Residual	0.019	0.75	50.7	64
Field Erected Watertube Boiler Stoker	Spreader	Coal	–	0.037	0.625	118.0	47
	Underfeed	Coal	–	0.016	0.625	50.6	73

[a] NO_2 basis

[b] Uncontrolled basis

[c] Lignite includes sub-bituminous – Residual includes crude oil

Table 2-2. SUMMARY OF EMISSIONS, EMISSION FACTORS, AND FUEL USAGE BY EQUIPMENT CATEGORIES FOR STEAM GENERATION – INDUSTRIAL BOILERS

Equipment Type	Firing Type	Fuel	Fuel Type*	NO_x 10^6 TPY	LB $NO_x/10^6$ Btu Emission Factor	Fuel Usage 10^{12} Btu	Numerical Ranking
Field Erected Watertube Boilers >100 MM Btu/hr	Tangential Firing	Coal	–	0.030	0.75	80.0	52
		Oil	Residual	0.106	0.357	593.8	28
		Gas	Natural	0.032	0.249	257.0	51
			Process	0.004	0.23	34.8	108
	Horizontally Opposed Wall Firing	Coal, Dry Bottom	–	0.009	0.75	24.0	90
		Coal, Wet Bottom	–	0.003	1.25	4.8	112
		Oil	Residual	0.165	0.573	575.9	18
		Gas	Natural	0.087	0.249	303.7	31
			Process	0.009	0.23	78.3	92
	Front Wall Firing	Coal, Dry Bottom	–	0.009	0.75	24.0	91
		Coal, Wet Bottom	–	0.003	1.25	4.8	112
		Oil	Residual	0.165	0.573	575.9	17
		Gas	Natural	0.059	0.249	205.9	36
			Process	0.007	0.23	60.7	102
	Vertical Firing	Coal, Dry Bottom	–	0.002	0.75	5.3	119
	Cyclone	Coal, Wet Bottom	–	0.028	1.6	35.0	55
		Oil	Residual	0.014	0.573	48.9	79
Field Erected Watertube Boilers 10–100 MM Btu/hr	Wall Firing	Oil	Distillate	0.007	0.172	81.4	100
			Residual	0.086	0.423	406.6	32
		Gas	Natural	0.045	0.17	529.4	41
			Process	0.002	0.17	23.5	122
Field Erected Watertube Boilers Stokers	Spreader	Coal	–	0.136	0.417	435.2	21
	Underfeed	Coal	–	0.077	0.417	246.4	33
	Overfeed	Coal	–	0.037	0.625	118.4	48
	General, Not Classified	Coal	–	0.018	0.417	57.6	67
Packaged Watertube Bent Tube Straight Tube (Obsolete)	Wall Firing	Coal	–	0.009	0.75	24.0	93
		Oil	Distillate	0.0156	0.153	203.9	27
			Residual	0.2064	0.377	1095.0	13
		Gas	Natural	0.139	0.167	1664.7	20
			Process	0.007	0.167	83.8	101

*Process gas includes coke oven gas and blast furnace gas.

Table 2-2. SUMMARY OF EMISSIONS, EMISSION FACTORS, AND FUEL USAGE BY EQUIPMENT CATEGORIES FOR STEAM GENERATION – INDUSTRIAL BOILERS (Continued)

Equipment Type	Firing Type	Fuel	Fuel Type	NO_x 10^6 TPY	LB $NO_x/10^6$ Btu Emission Factor	Fuel Usage 10^{12} Btu	Numerical Ranking
Packaged Watertube Stoker	Spreader	Coal	–	0.043	0.417	206.0	43
	Underfeed	Coal	–	0.067	0.417	321.3	35
	Overfeed	Coal	–	0.016	0.625	51.2	75
	General, Not Classified	Coal	–	0.007	0.417	33.6	98
Packaged Firetube Scotch	Wall Firing	Oil	Distillate	0.0156	0.153	203.9	76
			Residual	0.1924	0.377	1021.0	14
		Gas	Natural	0.044	0.167	526.9	42
			Process	0.001	0.167	12.0	133
Packaged Firetube Firebox	Wall Firing	Oil	Distillate	0.006	0.153	78.4	104
			Residual	0.076	0.377	403.2	34
		Gas	Natural	0.038	0.167	455.1	46
			Process	0.001	0.167	12.0	132
Packaged Firetube Firebox Stoker	Spreader	Coal	–	0.002	0.417	9.6	120
	Underfeed	Coal	–	0.010	0.417	48.0	86
	Overfeed	Coal	–	0.002	0.625	6.4	119
Packaged Firetube HRT	Wall Firing	Oil	Distillate	0.003	0.153	39.2	113
			Residual	0.040	0.377	212.2	45
		Gas	–	0.020	0.167	239.5	63
Packaged Firetube HRT Stoker	Spreader	Coal	–	0.001	0.417	4.8	130
	Underfeed	Coal	–	0.005	0.417	24.0	107
	Overfeed	Coal	–	0.001	0.625	3.2	131

Table 2-3. SUMMARY OF EMISSIONS, EMISSION FACTORS, AND FUEL USAGE BY EQUIPMENT CATEGORY FOR COMMERCIAL BOILERS

Equipment Type	Firing Type	Fuel	Fuel Type	NO_x 10^6 TPY	LB $NO_x/10^6$ Btu Emission Factor	Fuel Usage 10^{12} Btu	Numerical Ranking
Packaged Firetube Scotch	Wall Firing	Oil	Distillate	0.0184	0.172	214.0	65
			Residual	0.0452	0.423	214.0	39
		Gas	–	0.036	0.100	720.0	49
Packaged Firetube Firebox	Wall Firing	Oil	Distillate	0.0184	0.172	214.0	66
			Residual	0.0452	0.423	214.0	40
		Gas		0.036	0.100	720.0	50
Packaged Firetube Firebox, Stoker	All Categories	Coal	–	0.018	0.250	144.0	71
Packaged Firetube HRT	Wall Firing	Oil	Distillate	0.0092	0.172	107.0	87
			Residual	0.0226	0.423	107.0	62
		Gas	–	0.018	0.100	360.0	68
Packaged Firetube HRT, Stoker	All Categories	Coal	–	0.009	0.250	72.0	94
Packaged Firetube, General, Not Classified	Wall Firing	Oil	Distillate	0.0031	0.172	36.0	111
			Residual	0.007	0.423	33.1	98
		Gas	–	0.006	0.100	120.0	103
	Stoker and Handfire	Coal	–	0.002	0.250	16.0	121
Packaged Cast Iron Boilers	Wall Firing	Oil	Distillate	0.0092	0.172	107.0	88
			Residual	0.0226	0.423	107.0	61
		Gas	–	0.018	0.080	450.0	20
Packaged Watertube Coil	Wall Firing	Oil	Distillate	0.001	0.172	11.6	125
			Residual	0.003	0.423	14.2	114
		Gas	–	0.0024	0.100	48.0	116
Packaged Watertube Firebox	Wall Firing	Oil	Distillate	0.0006	0.172	6.98	134
			Residual	0.002	0.423		123
		Gas	–	0.001	0.100	20.0	127
Packaged Watertube General, Not Classified	Wall Firing	Oil	Distillate	0.001	0.172	11.6	126
			Residual	0.003	0.423	14.2	115
		Gas	–	0.0024	0.100	48.0	117

Table 2-4. SUMMARY OF EMISSIONS, EMISSION FACTORS, AND FUEL USAGE BY EQUIPMENT CATEGORY FOR SPACE HEATING, RESIDENTIAL HEATERS

Equipment Type	Firing Type	Fuel	Fuel Type	NO_X 10^6 TPY	LB $NO_X/10^6$ Btu Emission Factor	Fuel Usage 10^{12} Btu	Numerical Ranking
Steam or Hot Water Heaters		Oil	Distillate	0.097	0.114	1698.0	30
		Gas	–	0.040	0.082	975.6	44
Hot Air Furnaces		Oil	Distillate	0.107	0.114	1873.0	26
		Gas	–	0.106	0.082	2858.0	27
Floor, Wall, or Pipeless Heaters		Oil	Distillate	0.016	0.114	280.0	74
		Gas	–	0.027	0.082	658.5	56
Room Heater With Flue		Oil	Distillate	0.024	0.114	420.0	59
		Gas		0.028	0.082	682.9	53
Room Heater Without Flue		Oil	Distillate	0.010	0.082	268.3	83

Table 2-5. SUMMARY OF EMISSIONS, EMISSION FACTORS, AND FUEL USAGE BY EQUIPMENT CATEGORY FOR INTERNAL COMBUSTION ENGINES

Equipment Type	Firing Type	Fuel	Fuel Type	NO_x 10^6 TPY	LB $NO_x/10^6$ Btu Emission Factor	Fuel Usage 10^{12} Btu	Numerical Ranking
Reciprocating Engines	Spark Ignition	Gas	–	1.873	3.66	1023.0	1
	Diesel	Oil and Dual	–	0.316	2.69	234.9	8
Gas Turbines		Gas	–	0.172	0.57	604.2	16
		Oil	–	0.119	0.84	284.0	23

Table 2-6. SUMMARY OF EMISSIONS FOR INDUSTRIAL PROCESS HEATING EQUIPMENT

Industry	Application	Fuel	NO_x 10^6 TPY	Numerical Ranking
Glass Manufacture	Melting Furnaces	Oil	0.055	25
		Gas	0.055	25
Petroleum Industry	Fluid Catalytic Crackers	Oil	0.049	29
		Gas	0.05	29
Cement Industry	Drying Kilns	Oil	0.0165	37
		Gas	0.047	38
		Coal	0.055	72
Steel and Iron Industries	Coke Oven Underfire	Gas	0.0059	106
	Heating Annealing Ovens	Oil	0.002	106
		Gas	0.0036	106
	Open Hearth Ovens		0.025	52
	Sintering		0.024	58
Brick Manufacture	Curing Ovens	Oil	0.0003	135
		Gas	0.0003	137

Table 2-7. SUMMARY OF EMISSIONS FOR INCINERATION

Industry	Application	Fuel	NO_x 10^6 TPY	Numercial Ranking
Incineration	Industrial		0.023	66
	Municipal		0.019	69

Table 2-8. SUMMARY OF EMISSIONS FOR NON-COMBUSTION SOURCES

Industry	Application	Fuel	NO_x 10^6 TPY	Numerical Ranking
Acid Manufacture	Nitric		0.11	24
	Sulfuric		0.011	80
Explosive Manufacture			0.028	54

2.2 SUMMARY OF 1972 STATIONARY SOURCE NO_x EMISSIONS

A summary of the 1972 NO_x emissions by sector and fuel are presented in Tables 2-9 and 2-10, respectively. The total of 11.665 million tons per year of NO_x from stationary sources is dominated by coal burning utility boilers (32.5 percent) and gas fired reciprocating IC engines (16.06 percent). Figure 2-2 graphically illustrates the relative magnitudes of each of the sectors. Examination of this chart indicates that steam raising boilers (utility, industrial and commercial) contribute greater than 70 percent of the total uncontrolled stationary source NO_x production.

Re-examination of the two primary sources of stationary NO_x production - coal fired utility boilers (32.5 percent) and gas fired reciprocating IC engine (16.06 percent) - indicates that in terms of energy consumption, coal fired utility boilers consume 19.7 percent but gas fired IC engines consume only 2.4 percent of the total energy used. While coal fired utility boilers are the greatest fuel user, reciprocating IC engines rank approximately 16th in fuel consumption. This discrepancy is explained by the respective emission factors of each equipment type. Utility boilers have an emission factor approximately one-fifth that of IC engines. This point illustrates the need for accurate and up-to-date emission factors.

Previous inventories are compared to present data in Tables 2-11 and 2-12. Note that considerable differences exist in the manner in which sectors are distinguished, particularly in the IC engine category.

2.3 NO_x EMISSION TRENDS AND PROJECTIONS

Nationwide NO_x emission trends from 1940 to 1972 as compiled by the EPA (Reference 2-3) are illustrated in Figure 2-3. In general, stationary sources are believed to comprise slightly more than 50 percent of the total NO_x production, and this is shown to be a consistent assumption in the figure. Figure 2-4 compares the EPA figures with the ESSO (Reference 2-2) estimates published in 1968. The slight downward trend in 1971 of the EPA data is due to revised emission factors and implementation of NO_x controls on the West Coast. As can be seen from the figure, 1972 emissions have already attained the 1978 ESSO estimates.

Projections for nationwide NO_x emissions have been made by the National Academy of Sciences (Reference 2-4) based on several assumptions, including consideration for various control options. These projections are presented in Table 2-13 assuming completion of the present stationary program. These estimates are considered conservative since growth rates are historically greater than projected. Assumptions made for these projections are:

- Most new electric power generation will be produced with nuclear reactors
- The stationary automotive regulations will remain in effect and be achieved

Table 2-9. SUMMARY OF TOTAL NO_x EMISSIONS FROM FUEL USER SOURCES (1972) (Ref. 1)

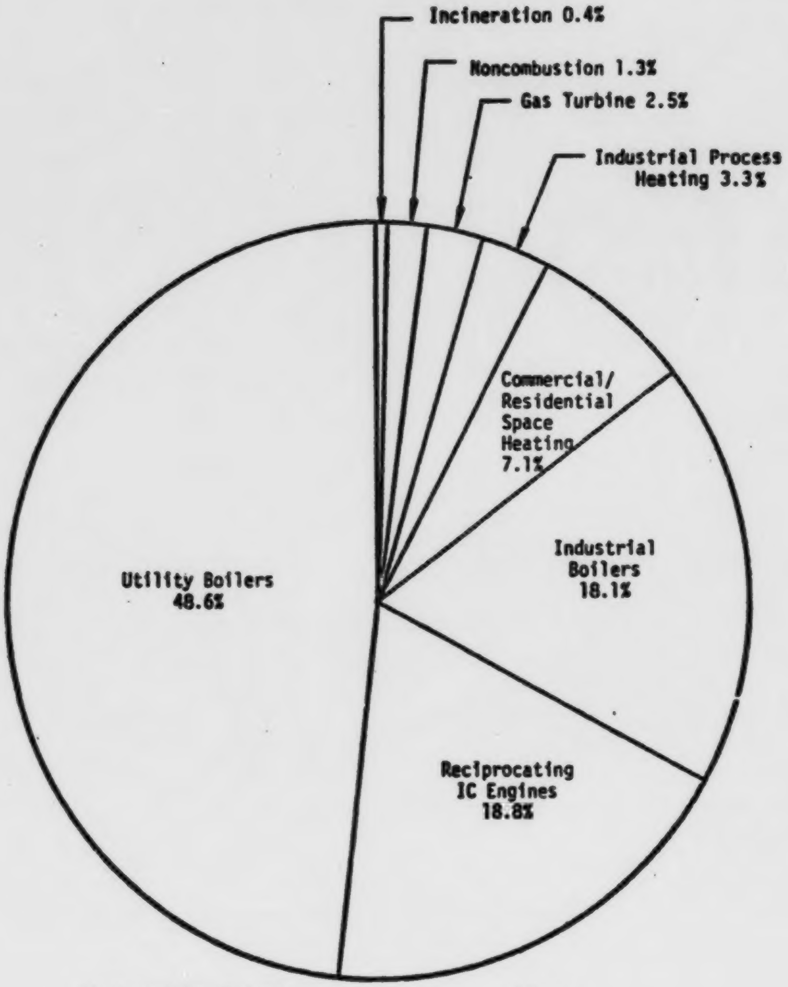
Sector	NO_x Production 10^6 ton/yr (percent of total)			Totals By Sector 10^6 ton/yr (percent of total)	Cumulative Percentage
	Gas	Coal	Oil		
1. Utility Boilers	1.114 (9.55)	3.788 (32.47)	0.768 (6.58)	5.670 (48.61)	48.61
2. IC Engines					
Reciprocating	1.873 (16.06)	–	0.316 (2.71)	2.189 (18.77)	67.38
Gas Turbines	0.172 (1.47)	–	0.119 (1.02)	0.291 (2.49)	69.87
3. Industrial Boilers	0.495 (4.24)	0.515 (4.41)	1.098 (9.41)	2.108 (18.07)	87.94
4. Commercial/Residential Heating	0.3308 (2.84)	0.029 (0.25)	0.467 (4.00)	0.8268 (7.09)	95.03
5. Process Heating	0.1855 (1.59)	0.0553 (0.47)	0.149 (1.28)	0.3902 (3.35)	98.38
6. Non-Combustion	–	–	–	0.149 (1.28)	99.66
7. Incineration	–	–	–	0.041 (0.35)	100
Totals by Fuel	4.1703 (35.75)	4.3873 (37.61)	2.9174 (25.01)	11.665 (100)	

NO_2 basis uncontrolled

Table 2-10. SUMMARY OF FUEL USAGE* 1972 (Ref. 1)

	Fuel Usage – 10^{12} Btu/yr (percent of total)			
	Gas	Coal	Oil	Total
1. Utility Boilers	3766 (8.81)	8420 (19.7)	2594 (6.1)	14,780 (34.6)
2. IC Engines				
Reciprocating	1023 (2.4)	–	235 (0.5)	1,258 (2.94)
Turbines	604 (1.4)	–	284 (0.7)	888 (2.1)
3. Industrial Boilers	4487 (10.5)	1768 (4.1)	5539 (13.0)	11,794 (27.6)
4. Commercial Boilers	2486 (5.8)	232 (0.5)	1421 (3.3)	4,139 (9.7)
5. Residential Heating	5443 (12.7)	–	4446 (10.4)	9,889 (23.1)
	17,809 (41.7)	10,420 (24.4)	14,519 (34.0)	42,748 (100)

*Excludes process fuel



Estimated NO_x Emissions Tons/Year	Source
5,670,000	Utility Boilers
2,189,000	Reciprocating IC Engines
2,108,000	Industrial Boilers
826,800	Commercial/Residential Heating
390,200	Industrial Process Heating
291,000	Gas Turbines
149,000	Noncombustion
41,000	Incineration
11,665,000	TOTAL

Figure 2-2. Summary of 1972 stationary source NO_x emissions.

Table 2-11. COMPARISONS OF NO_x EMISSIONS

	10^6 TPY				
	Aerotherm (1972)	ESSO (1970)	AP-115 (1970)	OAQPS (1971)	AS/NEDS (1973)
Utility Boilers	5.67	3.84	4.71	5.38	5.77
IC Engines	(2.48)				
Reciprocating	2.19	2.10[b]	d	d	
Gas Turbines	0.29	a	d	d	
Industrial Boilers	2.11	2.81	4.53	3.90	1.41
Commercial	0.36	1.00	0.23	0.586	
Residential	0.47	1.00	0.57	0.586	
Process Heating	0.39	a	0.20	a	
Non-Combustion	0.149	0.24	–	0.20	
Incineration	0.04	a	0.08	0.04	
Other	e	c	e		
Total	11.67	9.99	10.32	10.11	

[a] Included in industrial size boilers

[b] Pipeline and gas plants only

[c] Included in non-combustion

[d] Included in utility and industrial depending on use

[e] Not included in data

Table 2-12. FUEL CONSUMPTION COMPARISONS

	10^{15} Btu		
	MSST (1972)	OAQPS (1971)	AP-115 (1969)
Utility Boilers	14.78	14.04	12.14
IC Engines			
Reciprocating	1.26	16.86	16.11
Gas Turbine	0.89		
Industrial Boilers	11.79		
Commercial	4.14	12.2	11.57
Residential	9.89		
Total	42.75	43.1	39.82

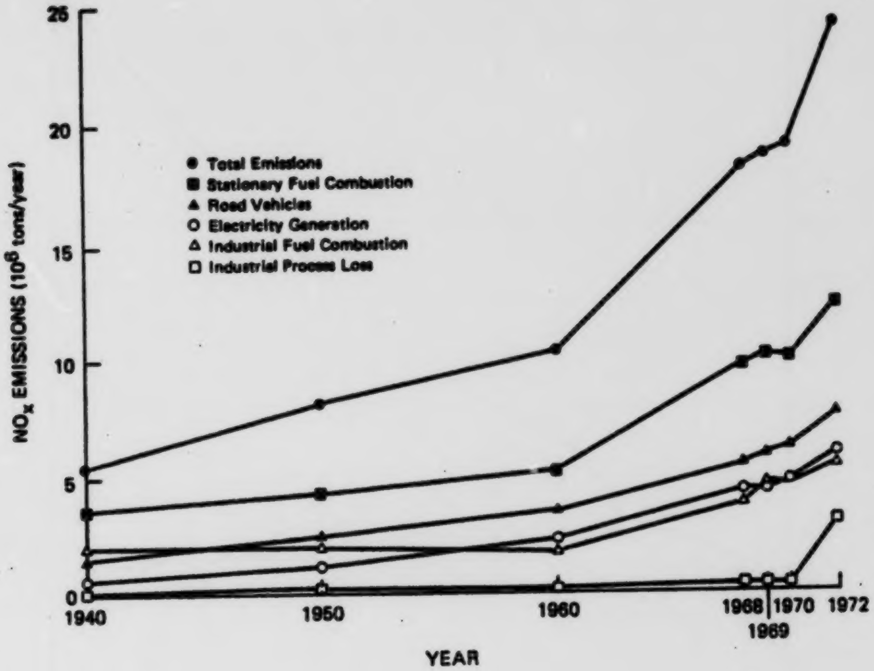


Figure 2-3. Nationwide NO$_x$ emission trends 1940 — 1972 (Reference 2-4).

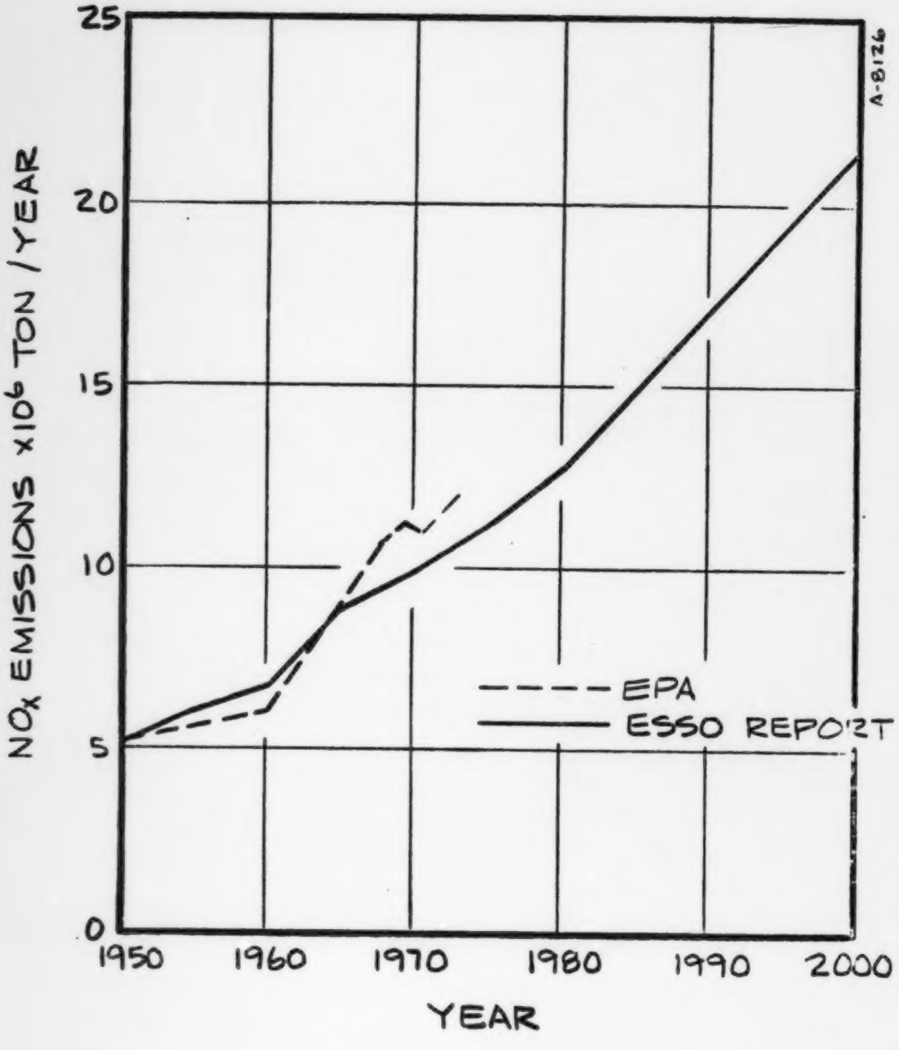


Figure 2-4. Stationary source NO_x emission trends.

TABLE 2-13. NATIONWIDE NO_x EMISSIONS PROJECTED TO 1990 ASSUMING THE PRESENT STATUTORY PROGRAM

Source Category	NO_x Emissions (10^6 tons/year)			
	1972	1980	1985	1990
Stationary Fuel Combustion	12.27	15.96	16.82	18.46
Electric Generation	5.94	8.16	8.20	8.88
Industrial	5.39	6.73	7.46	8.31
Commercial-Institutional	0.65	0.76	0.84	0.93
Residential	0.29	0.31	0.32	0.34
Industrial Process Losses	2.88	3.91	4.72	5.71
Solid Waste Disposal	0.18	0.22	0.25	0.28
Transportation[a]	8.45	8.47	7.49	7.60
Road Vehicles	7.48	7.14	5.89	5.68
Gasoline	6.59	5.97	4.30	3.95
Diesel	0.89	1.17	1.59	1.73
Other	0.97	1.33	1.60	1.92
Miscellaneous[b]	0.59	0.74	0.87	1.02
TOTAL	24.37	29.30	30.15	33.07

[a] Assumes a 4% annual VMT growth rate

[b] Includes New York City Point sources assumed to grow at 4% per year

- The 1940 - 1972 growth rate of NO_x emissions from industrial, commercial, and institutional sources will be reduced over the next twenty years.

These estimates assume the completion of Project Independence, which depends strongly on NO_x free-nuclear power. Utility NO_x generation would almost double if energy requirements were to be met only with coal, as shown in Table 2-14. The uncertainty of projections of this nature is compounded by several trends beginning to emerge due to recent energy shortages and fuel unavailability:

- There will be a significant increase in the utilization of coal and oil in power generation, leading to an intensified NO_x problem.
- Industrial area sources may be switching to oil or coal if the energy shortage continues, resulting in larger potential NO_x production.
- Greater emphasis on alternate fuels, the results of which are impossible to quantify at this time.
- Home heating systems will become more efficient if the cost of fuel continues to rise and this could result in increased NO_x emissions.

Other significant factors affecting future NO_x emission include the following:

- Major technological developments in equipment design, fuels and fuel treatment, combustion control and exhaust gas cleanup.
- Uncertainty concerning the future of nuclear energy as a major source of electrical power.
- The degree to which NO_x emissions will be regulated by both local and federal restrictions.

TABLE 2-14. NATIONWIDE EMISSIONS OF NO_x FROM ELECTRIC POWER GENERATION PROJECTED TO 1990 FOR TWO POLICY OPTIONS

	NO_x Emissions (10^6 tons/year)							
	Project Independence				No New Nuclear Plants Built After 1975			
Year	Total[a]	Coal	Oil	Natural Gas	Total[a]	Coal	Oil	Natural Gas
1972	5.94	3.95	0.85	1.14	5.94	3.95	0.85	1.14
1980	8.24	7.21	0.52	0.48	9.32	8.29	0.52	0.48
1985	8.20	7.21	0.52	0.44	12.81	11.82	0.52	0.44
1990	8.88	7.89	0.52	0.44	17.56	16.57	0.52	0.44

[a] Total contains 0.03×10^6 tons/year from gas turbines

Reference 2-4

REFERENCES

2-1 Mason, H. B. and A. B. Shimizu, "Definition of the Maximum Stationary Source Technology (MSST) Systems Program for NO_x," (Draft Report) Aerotherm Final Report 74-123, Acurex Corporation, Aerotherm Division, October 1974.

2-2 Bartok, W. et al., "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources – Vol. II, Prepared for National Air Pollution Control Administration, NTIS Report No. PB-192-789, Esso Research and Engineering, 1969.

2-3 Cavender, J. H. and D. S. Kircher and A. I. Hoffman, "Nationwide Air Pollutant Emission Trends 1940 – 1972, "Pub. No. AP-115, Environmental Protection Agency, Research Triangle Park, North Carolina, January 1973.

2-4 National Academy of Sciences, "Air Quality and Stationary Source Emission Control," Prepared for the Committee on Public Works, United States Senate, Serial No. 94-4, March 1975.

2-5 "OAQPS Data File of Nationwide Emissions – 1971," Office of Air Quality Planning and Standards, Environmental Protection Agency, May 1973.

2-6 Letter from Owen W. Dykema, Aerospace Corporation to Robert E. Hall, EPA of 11 March 1974, Reference 74-3310-OWD-5, Aerospace Corporation, Los Angeles, California.

SECTION 3

SUMMARY OF STATIONARY SOURCE NO_x CONTROL TECHNIQUES

Combustion generated NO_x results either from thermal fixation of atmospheric nitrogen in the combustion air or, in the case of nitrogen-containing fuels such as residual oil and coal, from conversion of chemically bound nitrogen in the fuel. In both cases, NO_x emissions for a given equipment type are dependent on the fuel and on the combustion conditions in the primary flame zone. NO_x control can accordingly be approached through the following options.

- Modification of combustion conditions to suppress NO_x formation
- Modification or substitution of fuel
- Treatment of flue gas for NO_x removal
- Substitution of an alternate low NO_x combustion process

Table 3-1 gives an overview of the status, limitations and applications of these options.

In the near term, combustion modification is the most effective control option for retrofit of existing equipment and improved low NO_x design of new equipment. In the far term, substitution of alternate processes and use of clean fuels is likely to contribute to the strategy for maintenance of air quality for NO_x. Combustion modification used either with these advanced processes or with conventional fuels and equipment is likely to remain the predominant strategy for NO_x control. Supplemental control by flue gas treatment may be effective in the far term to achieve control levels beyond the limits of combustion modification.

3.1 COMBUSTION MODIFICATION

Thermal NO_x formation in continuous combustion devices is kinetically controlled and exhibits a strong dependence on flame temperature, and to a lesser degree, on local oxygen level. Suppression of thermal NO_x results from the following:

- Decreased flame temperature through dilution, modified stoichiometry, or increased heat transfer
- Decreased oxygen level at peak temperature through dilution or modified stoichiometry

TABLE 3-1. EVALUATION OF NO_x CONTROL TECHNIQUES

Technique	Principle of Operation	Status of Development	Limitations	Applications	
				Near Term	Long Term
Combustion Modification	Suppress thermal NO_x through reduced flame temperature, reduced O_2 level; suppress fuel NO_x through delaying fuel/air mixing or reduced O_2 level in primary flame zone	Operational for point sources; pilot-scale and full scale studies on combined modifications, operational problems and advanced design concepts for area sources	Degree of control limited by operational problems	Retrofit utility, industrial boilers, gas turbines; improved designs	Optimized design area, point sources
Flue Gas Treatment	Reduction of NO to N_2 by catalytic treatment; scrubbing or absorption of NO or NO_2	Operational for concentrated effluents from nitric acid plants; pilot scale feasibility studies for conventional combustion systems	High make-up ratio of reducing agent or absorbent; interference by fuel sulfur or metallic compounds	Non-combustion sources (nitric acid plants)	Possible supplement to combustion modifications; simultaneous SO_x/NO_x removal
Fuel Switching	Simultaneous SO_x and NO_x control by conversion to clean fuels; synthetic gas or oil from coal; SRC; methanol; hydrogen	Synthetic fuel plants in pilot-scale stage; commercial plants due by mid 1980's	Fuel cost differential may exceed NO_x, SO_x, control costs with coal	Negligible use	New point sources, (combined cycle) Convert area sources (residential)
Fuel Additives	Reduce or suppress NO by catalytic action of fuel additives	Inactive; preliminary screening studies indicated poor effectiveness	Large make-up rate of additive for significant effect; presence of additive as pollutant	Negligible use	Not promising
Fuel Denitrification	Removal of fuel nitrogen compounds by pretreatment	Oil desulfurization yields partial denitrification	Effectiveness for coal doubtful; no effect on thermal NO_x	Negligible use	Supplement to combustion modification
Catalytic Combustion	Heterogeneously catalyzed reactions yields low combustion temperature, low thermal NO_x	Pilot-scale test beds for catalyst screening, feasibility studies	Limited retrofit applications; requires clean fuels	Small space heaters	Possible use for residential heating, small boilers
Fluidized Bed Combustion	Coal combustion in solid bed yields low temperature, low NO_x	Pilot-scale study of atmospheric, pressurized beds; focus on sulfur retention devices	Fuel nitrogen conversion may require control (staging) may require large make-up of limestone sulfur absorbent	Negligible use	Utility, industrial boilers beginning mid 70's; possible combined cycle, waste fuel application

- Reduced residence time at peak temperature through controlled mixing

The detailed mechanisms for fuel nitrogen conversion are not fully understood but empirical tests indicate that delayed mixing of oxygen with the nitrogen bearing fuel effectively suppresses 50 to 90 percent of fuel nitrogen conversion.

The technique developed to control NO_x by the above general principles are strongly dependent on equipment characteristics such as combustion chamber configuration, flame heat transfer, and fuel/air aerodynamics. The following subsections summarize the status and prospects of combustion modifications for the major stationary source combustion equipment types.

3.1.1 Utility Boilers

Utility boilers, due to their importance as NO_x sources and their control flexibility, are the most extensively modified stationary equipment type. The selection and implementation of effective NO_x controls for given utility boilers is uniquely dependent on the furnace characteristics, fuel/air handling systems and control systems, and to the occurance of operational problems which may result from combustion modifications. The following discussion is therefore not intended to provide application guidelines, but rather to give a broad overview and evaluation of tested procedures.

Table 3-2 summarizes the status of combustion modification technology for NO_x control in utility boilers. The references cited in the table are the basis for the remainder of the discussion in this section. The table also lists typical values of controlled emissions for the major modification techniques and the two major firing types, tangential firing and wall firing. For reference, the range of uncontrolled emissions (ppm at 3 percent O_2) for these firing types are as follows (Reference 3-11):

	Gas	Oil	Coal
Tangential	100 - 350	100 - 350	300 - 600
Wall firing	130 - 950	200 - 550	400 - 900

Low excess air (LEA) firing is the most widely used technique for control of both thermal and fuel NO_x. LEA is also effective for increasing unit thermal efficiency. Its use is limited by the increase in smoke or CO emissions which occur at low levels of excess air. Also, for certain primarily eastern coals, the localized reducing conditions in the lower furnace which result from LEA firing can produce accelerated fireside corrosion and slagging. Low excess air firing is typically the first technique implemented as part of a control program and is normally included when other techniques are used. The minimum excess air level achievable when other controls, such as staging, are used is typically higher than when LEA is applied singly.

TABLE 3-2. SUMMARY OF COMBUSTION MODIFICATION TECHNIQUES FOR LARGE BOILERS[1]

Technique	Principle of Operation	Emission Rates (NO_x) NO_2 basis @ 3% O_2[2]	Limitations	Existing Applications	Applications Planned for Next 5 Years	Reference
Staged combustion with tangential firing	Lower nozzles operated fuel rich yielding reduced O_2 level in primary zone and suppression of thermal and and fuel NO_x	Gas: 100-150 ppm Oil: 125-225 ppm Coal: 200-300 ppm	Fouling of convective section; poor primary stage ignition; soot formation; possible load reduction	Retrofit of utility boilers, large industrial boilers	Inclusion of overfire air ports in new unit design	(3-1)-(3-7)
Staged combustion with wall firing	Biased burner firing or oversize air ports reduces O_2 level in primary flame zone and suppresses thermal and fuel NO_x	Gas: 200-300 ppm Oil: 250-350 ppm Coal: 350-450 ppm	Corrosion with coal firing, fouling of convective section, boiler	Retrofit of utility boilers, large industrial boilers	Inclusion of overfire air ports in new unit design	(3-4)-(3-8)
Flue gas recirculation	Recycled flue gas reduces primary flame temperature and suppresses thermal NO_x	Gas: 80-120 ppm (tangential) 250-350 ppm (wall firing) Oil: 150-220 ppm (tangential) 250-350 ppm (wall firing)	Reduced effect with coal, heavy oils; flame instability	Retrofit of gas and distillate oil utility boilers	Inclusion in design of large industrial boilers	(3-4)-(3-8)
Low excess air firing	NO_x control through reduced O_2 level in primary flame zone	Gas: 200-250 ppm (tangential) 300-350 (wall firing) Oil: 200-250 (tangential) 300-350 (wall firing) Coal: 350-450 (tangential) 450-600 (wall firing)	Unburned hydrocarbons, CO emissions at low levels of excess air; increased fouling	Routine use in utility boilers; limited use in industrial boilers	Application to commercial and industrial boilers as part of energy conservation programs	(3-1)-(3-8)

[1] Combined modifications are excluded; the NO_x control with combined modifications is generally less than the additive effects of the modifications applied singly.

[2] Emission rates cited are nominal values for average unit capacity and operating conditions; the range of available data is much wider than the values reported.

TABLE 3-2. (Concluded)

Technique	Principle of Operation	Emission Rates (NO_x) NO_2 Basis @ 3% O_2	Limitations	Existing Applications	Applications Planned for Next 5 Years	Reference
Low air preheat	Reduced combustion air temperature yields lower flame temperature and lower NO_x	—	Reduced plant thermal efficiency	—	—	(3-1),(3-6)
Water injection	Reduced flame temperature, possible emulsion effect	—	Reduced thermal efficiency; severe operational problems with high level of water injection	—	—	
New burner designs	Controlled mixing of fuel/air yields control of thermal, fuel NO_x	Gas: 150-200 ppm Oil: 200-250 ppm Coal: 450-550 ppm	NO_x control through retrofit constrained by firebox configuration	—	Inclusion in new unit design for utility and industrial boilers	(3-9),(3-10)

Staging is a very effective technique for control of both thermal and fuel NO_x. By this approach, biased burner firing or overfire air ports are used to control the mixing of the fuel with the combustion air. The resulting fuel rich regions in the primary flame zone are cooled by flame radiation heat transfer prior to completion of combustion with the remaining combustion air. Thus, although the overall fuel/air mixture is near-stoichiometric, the primary NO_x forming region of the flame is operated at a non-stoichiometric, low NO_x condition. NO_x control effectiveness with staging depends on burner or primary stage stoichiometry which in turn is limited by convective section fouling, unburned hydrocarbon emission or poor ignition characteristics which occur at excessively rich operation. An additional limitation of fireside corrosion may arise with the firing of some coals and heavy oils.

Advanced burner design is an alternate method for thermal and fuel NO_x reduction through controlled mixing of fuel and air. With modified burner design, the basic NO_x control principles underlying staging and flue gas recirculation can be incorporated internal to the furnace thereby avoiding some of the operational problems normally associated with external staging or FGR. Advanced burner designs are particularly attractive for application to new units where the burner can be matched to the firebox configuration.

Flue gas recirculation (FGR) has been implemented to a limited extent for control of thermal NO_x with the firing of natural gas and oil. FGR does not appear to be effective for control of fuel NO_x emissions. Thermal NO_x reductions achievable by FGR are limited by the occurance of flame instability and boiler rumble at high levels of recirculated flue gas.

Two additional control techniques, water injection and reduced air preheat, serve to control thermal NO_x by reduction of the primary zone flame temperature, but are not widely used due to adverse impact on thermal efficiency.

3.1.2 Industrial Boilers

As discussed in Section 2 and Appendix A, the industrial boiler source category consists of a diversity of design types over a wide capacity range. The largest field erected watertube units (>250 M Btu/hr) are similar in design to the smaller utility boilers. For these, NO_x control technology is well developed and is essentially the same as discussed above for utility boilers. For firetube boilers and the smaller watertube boilers, NO_x control technology is in the formative stages due primarily to the lack of regulatory incentive. For these small units, the NO_x control flexibility in terms of number of burners, fuel/air handling system, and control systems are much more limited than for utility boilers. With fewer NO_x control options available, retrofit control development and implementation becomes a far more individual process for each particular unit. With this situation, the NO_x control cost effectiveness for new unit design is expected to far exceed that for retrofit of existing units.

Field test experience for NO_x controls in industrial boilers is due largely to a continuing EPA funded study by KVB Engineering, Reference 3-12. The initial, complete, phase of the study involved emission characterization and testing of minor fine tuning modification for 75 boiler/burner/fuel combinations. The final, ongoing, phase of the study is focusing on testing more elaborate modifications on a fewer number of units. The range of uncontrolled base load emissions from the first phase of the study were 224-800 ppm, 100-619 ppm, and 50-375 ppm for coal, oil and gas units respectively. During the first phase, a number of boilers were tested for NO_x reduction response to low excess air firing and off-stoichiometric combustion. LEA was most effective for coal-fired stokers and oil-fired watertube units. The firetube boilers and gas-fired watertube units generally showed less NO_x reduction from LEA firing. For multiburner units, off-stoichiometric combustion was achieved by adjusting burner stoichiometry or by taking burners out of service. This resulted in NO_x emission reduction of up to 40 percent. For stoker units, off-stoichiometric combustion was achieved by modification of existing overfire air ports. This resulted in NO_x reductions up to 25 percent.

3.1.3 Internal Combustion Engines

This section discusses state-of-the-art NO_x control techniques for reciprocating and gas turbine IC engines. It is emphasized that no nationwide and few local regulations exist at the present time and as a result, few of the controls discussed have seen extensive application even through research studies have found them effective. Reciprocating IC engines are presented in Section 3.1.3.1 and gas turbines are treated in Section 3.1.3.2.

3.1.3.1 Reciprocating IC Engines

Although stationary reciprocating engines account for nearly 20 percent of the NO_x from stationary sources, there are presently no regulations for gaseous emissions from these engines. Emission reduction techniques for stationary engines, however, have been investigated by many manufacturers, and numerous studies have reported emission control techniques for automotive diesel and gasoline fueled engines.[1] Emissions control research by manufacturers of stationary engines indicate several techniques currently available to the user. In addition, control techniques for automotive applications could be adapted to stationary applications.

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[1] Reference 3-13 provides a good overview of emissions from stationary engines, particularly large bore engines used in the oil and gas industry and for electric power generation. Reference 3-14 summarizes automotive technology available for stationary engines. Reference 3-15 is currently being completed and will represent the most comprehensive study of stationary reciprocating engines to date.

The stationary reciprocating engine industry has a multitude of applications and, therefore, discussions of emission reductions are more meaningful if the engines are subdivided into four characteristic groups, by size and fuel, that roughly correspond to their applications. Table 3-3 lists these groups and their principal applications, load factors, utilization, and typical emission levels. As Table 3-3 indicates, these engines display a wide range of emission potential depending on their design (2 or 4 stroke, naturally aspirated, turbocharged, aftercooled, open or divided chamber, etc.), fuel burned (natural gas, diesel oil, gasoline) and application.

Basically, NO_x control techniques must reduce emissions for a broad range of operating conditions ranging from rated load, continuous operation, to variable load, lower utilization applications. In general, large natural gas spark ignition engines have the highest NO_x emission factors and can significantly contribute to NO_x emissions when the engine is installed in gas compressor applications and runs continuously at rated load. Gasoline engines, in contrast, frequently operate at lower loads (less than 50 percent of rated) and produce substantially higher levels of CO and HC. NO_x control techniques for these engines often involve HC and CO control since these emissions frequently increase as NO_x is reduced. Note that divided chamber diesel-fueled engines produce low levels of NO_x (accompanied by greater fuel comsumption than open chamber designs) and that all diesel-fueled engines have relatively small HC and CO emissions (less than 3 gm/hp-hr and 10 gm/hp-hr respectively).

The following paragraphs will discuss NO_x control techniques in general and then specific NO_x reductions, by engine group, will be tabulated. (A lack of emission data precludes any discussion of natural gas engines less than 100 hp/cylinder). Section 4.3 will present typical control costs associated with emissions control for these engine categories.

Table 3-4 summarizes the principle combustion control techniques for reciprocating engines. These stategies may require adjustment of the engine operating conditions, addition of hardware, or a combination of both. Retard, air-to-fuel ratio change, derating, decreased inlet air temperature, or combinations of these controls appear to be the most viable control techniques in the near term. Nevertheless, there is some uncertainty regarding maintenance and durability of these techniques because, in the absence of regulation, very little data exists for controlled engines outside of laboratory studies, particularly for large non-automotive engines. In general, fuel consumption increases as large as 10 percent are the most immediate consequence of the application of these techniques (excluding inlet air cooling). These controls involve essentially operational adjustments with the exception of derating which would require additional units to compensate for the decreased horsepower and inlet manifold air cooling (addition of heat exchanger and pump).

TABLE 3-3. CATEGORIZATION OF STATIONARY RECIPROCATING ENGINE'S APPLICATIONS AND EMISSION FACTORS

Engine Category	Size	Speed, rpm	Principal Applications	Load Factor[a]	Utilization, hr/yr
DEMA, large bore high power. Natural gas, diesel and dual fueled	>100 hp/cyl	<1200 high, >600 medium, >300 low, <300	Gas compression	0.8	>6000
			Electric generation — base load	0.8	>6000
			— standby	0.8	<200
Medium bore, natural gas engines	>500 but <100 hp/cyl	>1200 but <1800	Gas compression	0.8	>6000
	<500 hp	>1800	Irrigation pumping	0.8	200-2000
Small and medium bore diesel fueled	<100 hp/cyl or <1000 hp	medium, >1200 high, >1800	Portable compressors, welders, pumps	<0.5	500
			Electric generators — continuous	0.8	500-1000
			— standby	0.8	<200
Gasoline engines	Small, 20 hp	>3000	Lawn and garden, small construction equipment	0.25	50
	Medium, 20-200 hp Large, 100-500 hp	>1800	Portable compressors, welders, pumps, electric generators (remote)	0.5	500-1000

[a] Percent of engine rated load

TABLE 3-3. (Concluded)

Engine Capacity		Emissions (gm/hp-hr)[e]			
		NO_x	CO	HC	bsfc[f]
DEMA, large bore high power. Natural gas, diesel and dual fueled	Gas: 2 & 4 stroke, NA, BS, TC	13-22	<10	<5	6500-8000 Btu/hp-hr
	Diesel: 2 & 4 stroke, NA, BS, TC	8-19	<8	<0.6	7000-7750 Btu/hp-hr
	Dual Fuel: 2 & 4 stroke, NA, BS, TC	8-15	<7	<6	6750-7250 Btu/hp-hr
Medium bore, natural gas engines	Gas: 2 & 4 stroke, NA, TC, TCI[b]	12-20	<10	<5	8000 Btu/hp-hr
Small and medium bore diesel fueled	Open Chamber[c]				
	— 2 stroke, BS	12-17	<10	<1	0.41-0.42 lb/hp-hr
	— 2 stroke, TC	8-9	<5	<1	0.38-0.39 lb/hp-hr
	— 4 stroke, NA	5-17	<10	<2	0.36-0.47 lb/hp-hr
	— 4 stroke, TC	9-16	<5	<3	0.39-0.41 lb/hp-hr
	Divided Chamber[c]				
	— 4 stroke, NA	2-4	<10	<0.5	0.53 lb/hp-hr
	— 4 stroke, TC	4-5	<1	<0.5	0.40-0.43 lb/hp-hr
Gasoline engines	Small 2 and 4 stroke, NA[d]	5.6	295	21	0.65 lb/hp-hr
	4 stroke, NA[c]				
	— rated load	9-16	10-50	2-4	0.58-0.76 lb/hp-hr
	— 23 mode composite cycle	8-14	30-90	3-13	

[b] Information supplied by manufacturers to Reference 3-15.

[c] Reference 3-14.

[d] Reference 3-16.

[e] To convert g/hp-hr to lb/10^6 Btu divide by ($4.54 \times 10^8 \times$ bsfc)

[f] Brake specific fuel consumption

TABLE 3-4. SUMMARY OF COMBUSTION MODIFICATION TECHNIQUES FOR RECIPROCATING IC ENGINES

CONTROL	PRINCIPLE OF REDUCTION	APPLICATION	BSFC INCREASE	COMMENTS — LIMITATIONS
RETARD Injection (CI)* Ignition (SI)†	Reduces peak temperatures by delaying start of combustion during the combustion stroke.	An operation adjustment. Delay cam or injection pump timing (CI); Delay ignition spark (SI).	Yes	Particularly effective with moderate amount of retard; further retard causes high exhaust temperature with possible valve damage and substantial bsfc increase with smaller NO_x reductions per successive degree of retard.
AIR-TO-FUEL (A/F) RATIO CHANGE	Peak combustion temperature is reduced by off-stoichiometric operation.	An operation adjustment. Increase or decrease to operate at off-stoichiometric mixture. Reset throttle or increase air rate.	Yes	Particularly effective on gas or dual-fuel engines. Lean A/F effective but limited by misfiring and poor load response. Rich A/F effective but substantial bsfc, HC, and CO increase. A/F less effective for diesel-fueled engines.
DERATING	Reduces cylinder pressures and temperatures.	An operation adjustment, limits maximum bmep** (governor setting).	Yes	Substantial increase in bsfc with additional units required to compensate for less power. HC and CO emission increase also.
INCREASED SPEED	Decreases residence time of gases at elevated temperature and pressure.	Operation adjustment or design change.	Yes	Practically equivalent to derating (increase speed, lower bmep, for given bhp requirement). Compressor applications constrained by vibration considerations. Not a feasible technique for existing and most new facilities.
DECREASED INLET MANIFOLD AIR TEMPERATURE	Reduces peak temperature.	Hardware addition to increase aftercooling or add aftercooling (larger heat exchanger, coolant pump)	No	Ambient temperatures limit maximum reduction. Raw water supply may be unavailable.
EXHAUST GAS RECIRCULATION (EGR) External	Dilution of incoming combustion charge with inert gases. Reduce excess oxygen and lower peak combustion temperature.	Hardware addition; plumbing to shunt exhaust to intake; cooling may be required to be effective; controls to vary rate with load.	No if EGR rates not excessive	Substantial fouling of heat exchanger and flow passages; anticipate increased maintenance. May cause fouling in turbocharged, aftercooled engine. Substantial increases in CO and smoke emissions. Maximum recirculation limited by smoke at near rated load, particularly for naturally aspirated engines.
Internal valve overlap or retard	Cooling by increased scavaging, richer trapped air-to-fuel ratio.	Operation/hardware modification: adjustment of valve cam timing	Yes	Not applicable on natural gas engine due to potential gas leakage during shutdown.
exhaust back pressure	Richer trapped air-to-fuel ratio	Throttling exhaust flow	Yes	Limited for turbocharged engines due to choking of turbocompressor.
CHAMBER MODIFICATION Pre-combustion (CI) Stratified charge (SI)	Combustion in ante-chamber permits lean combustion in main chamber (cylinder) with less available oxygen.	Hardware modification; requires different cylinder head.	Yes	5 to 10 percent increase in bsfc over open-chamber designs. Higher heat loss implies greater cooling capacity.
WATER INDUCTION	Reduces peak combustion temperature.	Hardware addition: inject water into inlet manifold or cylinder directly; effective at water-to-fuel ratio ≈ 1 (lb H_2O/lb fuel)	No	Deposit buildup (requiring demineralization); degradation of lube oil, cycling control problems.

*Compression ignition

†Spark ignition

**bmep — brake mean effective pressure.

While exhaust gas recirculation (EGR) exhibits effective reduction of NO_x, this technique will require additional development due to fouling of flow passages and increased smoke levels (vary EGR rate with load). In general, EGR is cooled in order to be effective and, hence, fouling arises. This technique has not been field tested for large engines, and has been rejected by one manufacturer of heavy duty diesel truck engines and limited by another manufacturer to potential application in turbocharged engines (no after-cooling) and naturally aspirated engines with full load EGR cut-off to prevent excessive smoke (> 10 percent opacity).* EGR, however, has been applied successfully in combination with other techniques (e.g., retard) in gasoline fueled automobile engines (Reference 3-14).

Water induction, similarly, has serious maintenance and durability problems associated with mineral deposit buildup and oil degradations. Despite demineralization of the water and increased oil changes, the control problems associated with engine start-up and shutdown and the necessity of a raw water source have led manufacturers to reject this technique.†

Combustion chamber modifications such as pre-combustion and stratified chambers have demonstrated large NO_x reductions, but also incur substantial fuel comsumption increases (5 to 8 percent more than open chamber designs). With the rapid increases in the price of diesel fuel and gasoline, manufacturers have been reluctant to implement this technique. In fact, one manufacturer of divided chamber engines is vigorously pursuing development of low emission open chamber engines.†

Table 3-5 gives emission reductions achieved by large bore engines for retard, air/fuel ratio changes, derating, and cooled inlet manifold air temperature (MAT). This table includes only those techniques from Table 3-4 which could be readily applied by the user. These reductions are based on results obtained from engines tested in manufacturers laboratories, therefore, some uncertainty exists concerning durability and maintenance over longer periods of operation.† In general, the greatest NO_x reductions are accompanied by the largest fuel consumption increases, which is a direct result of reducing peak combustion temperatures and, thus, decreasing thermal efficiency.

Numerous investigations have studied control techniques to reduce NO_x in diesel-fueled automotive truck applications, and many of these studies are summarized in Reference 3-14. Retard, turbocharging, aftercooling, derating and combinations of these controls are techniques that are currently utilized by manufacturers to meet California heavy duty vehicle (> 6000 lb) emission limits for diesel-fueled engines.

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*Based on information supplied by manufacturers to Reference 3-15.

†Based on published reports and information supplied by manufacturers to Reference 3-15.

TABLE 3-5. NORMALIZED PERCENT REDUCTIONS OF NO_x FOR LARGE BORE IC ENGINES

	Gas				Dual Fuel		Diesel		
	2		4		2	4	2		4
	BS	TC	NA	TC	TC	TC	BS	TC	TC
Baseline*	15.2	13.2	17.7-21.5	12.8-22.1	8.8	7.8-12.7	13.2-19.1	10.8-14.5	10.0-11.4
Retard	2.5	3.1	1.5	4.1-0.6	9.1	1.5-6-3	6.9	5.3-5.7	2.7-4.4
Air-to-Fuel	0.19	4.5	1.8	3.3	1.7	2.4-2.5	—	—	
Derate	6.2	2.6	0.25-1.3	0.34-1.9	—	0.01-0.94	0.84-0.92	—	0.17
MAT	0.9	1.3	—	0.4-0.9	1.3	0.6-0.8	0	0.2-0.4	0.1-0.3

*Baseline data in gm/bhp-hr, all other data in percent NO_x reduction/unit control. Unit control is 1° retard, 1 percent air flow increase, 1 percent derating, or 1°F air temperature decrease.

Brake Specific Fuel Consumption (bsfc), Percent Increase
For Large Bore IC Engines

Retard	5.2	4.3	3.6	1.2	3.4	1.0*	—	3.3*	2.2*
Air-to-Fuel	2.0	1.5	1.0	2.3	2.6	1.9	—	—	—
Derate	2.6	6.1	8.2*	1.1*	7.0*	—	3.4*	—	9.6
MAT	1.3	0.5	—	0	0.4	+0.5	—	1.6	0

*Average value.

Table 3-6 lists five examples of NO_x control techniques currently implemented by manufacturers to meet the 1975 California 10 gm/hp-hr NO_x + HC emission level. Manufacturers indicate that greater reductions will require increasing degrees of these controls (and additional fuel penalties) or application of techniques that are currently undeveloped or which will need further development to overcome maintenance, control, and durability problems. Such controls include EGR, water injection, and NO_x reduction catalysts.

Gasoline engine manufacturers, in response to Federal and State regulations, have also conducted considerable research of emission control techniques to reduce NO_x as well as HC and CO levels. Efforts in this area have been directed at reducing emissions to meet

1) Federal and California heavy duty vehicle (> 6000 lb) limits
2) Federal and California passenger car emissions limits.

Table 3-7a lists Federal and State emission limits, and Table 3-7b lists the various controls that are used in several combinations by manufacturers to meet these limits. Table 3-8 gives specific examples of control techniques recently applied to meet Federal light vehicle emission limits.

Based on the preceding discussions, potential NO_x emissions reductions for stationary reciprocating engines can be summarized as follows:

- Controls such as retard, air-to-fuel ratio change, turbocharging, inlet air cooling (or increased aftercooling), derating and combinations of these controls have been demonstrated to be effective and could be applied with no required lead time for development. Fuel penalties, however, accompany these techniques and may exceed 5 percent of the uncontrolled consumption.
- Exhaust gas recirculation, water induction, catalytic conversion and precombustion or stratified charge techniques involve some lead time to develop as well as time to address maintenance and control problems.
- NO_x control technology for automotive applications can be adapted to stationary engines; however, NO_x reductions and attendant fuel penalties for automotive applications are closely related to the load cycle, which in some cases may differ from stationary applications.
- Viable control techniques may involve an operational adjustment, hardware addition, or a combination of both.
- Additional research is necessary to
  - Establish controlled levels for gaseous-fueled engines < 100 hp/cylinder
  - Establish controlled levels for medium-powered diesel and gasoline engines based on stationary application load cycles
  - Supplement the limited emissions data available for large bore engines with field tested results.

TABLE 3-6. CONTROL TECHNIQUES FOR TRUCK SIZE DIESEL ENGINES (<500 HP) TO MEET 1975 CALIFORNIA 10 GM/HP-HR NO_x AND HC LEVEL*

Control	Bsfc† Increase	Source
Retard, modify fuel system and turbocharger	3 3	Information supplied to Reference 3-15 by manufacturers
Retard, modify fuel system and turbocharger, add aftercooler	2	Information supplied to Reference 3-15 by manufacturers
Add turbocharger and aftercooler §	0	Information supplied to Reference 3-15 by manufacturers
Retard § (Naturally aspirated version)	3	Information supplied to Reference 3-15 by manufacturers
Pre-combustion chamber	5 - 8	Information supplied to Reference 3-15 by manufacturers

*Based on Federal 13 mode composite cycle

†Bsfc = brake specific fuel consumption

§Stationary versions of this engine would require a cylinder head with 4 exhaust valves rather than existing 2 valves.

TABLE 3-7a. 1975 VEHICLE EMISSION LIMITS

	NO_x	HC	CO
Passenger Car, gm/mi (gm/hp-hr)*			
California	2.0 (4.4)	0.9 (2.0)	9 (19.6)
Federal	3.1 (6.8)	1.5 (3.3)	15 (32.8)
Light duty truck, gm/mi			
California	2.0 (4.4)	2.0 (4.4)	20 (43.7)
Federal	3.1 (6.8)	2.0 (4.4)	20 (43.7)
Heavy duty vehicles, gm/hp-hr			
California	10		30
Federal	16		40

*Emission limits are estimated in gm/hp-hr from gm/mile assuming an average speed of 24 mph requiring 11 bhp for the 7 mode composite cycle. See Reference 3-17.

TABLE 3-7b. EMISSION CONTROL TECHNIQUES FOR AUTOMOTIVE GASOLINE ENGINES

Control	Comment
NO_x:	
Rich or lean A/F ratio	Increased bsfc, HC, and CO
Ignition timing retard	Increased bsfc, HC, and CO, amount of control limited by potential exhaust valve damage
Exhaust gas recirculation (5 to 10 percent)	Increased bsfc and maintenance related to fouling, smoking limits degree of control
Catalytic convertors (reduction)	In developmental stage
Increase exhaust back pressure	Increase bsfc
Stratified combustion	Requires different cylinder head, increased bsfc.
HC, CO:	
Thermal reactor	Very effective in reducing HC, CO
Catalytic convertor (oxidation)	Requires periodic catalyst element replacement
Exhaust manifold air injection	Increased bsfc to power air pump
Positive crankcase ventilation	Reduces HC evaporative losses

TABLE 3-8. EMISSION CONTROL SYSTEMS FOR CONVENTIONAL GASOLINE I.C. ENGINES (ADAPTED FROM REFERENCE 3-18)

Number	Year	System	Fuel Penalty %(2)	Reduction Factors(2)			
				HC(3)	CO(3)	NO_x(3)	System Deterioration(4)
0	1972	EM°(1)	—	1 ± 0.375	1 ± 0.375	1 ± 20	L
1	1973 Federal	EM° + EI + FC + AI + EGR	7 ± 3	1.35 ± 0.30	1.0 ± 0.23	0.6 ± 0.10	L
2	1975 Federal	EM° + EI + IC + QHI + AI + EGR	5 ± 2	0.65 ± 0.15	0.55 ± 0.15	0.6 ± 0.10	L
3	1975 Calif.	EM° + EI + IC + QHI + EGR + AI + OC	8 ± 2	0.18 ± 0.05	0.15 ± 0.03	0.6 ± 0.10	M (HC, CO) L (NO_x)

(1)1972 baseline engine: modifications included in the baseline engine configuration are retard, lean air-to-fuel, and reduced compression ratio.

Component Identification

EM - Engine modifications; retard, air-to-fuel, compression ratio
EI - Electronic ignition
FC - Fast choke
QHI - Quick heat intake
AI - Exhaust manifold air injection
EGR - Exhaust gas recirculation
IC - Improved carburetion
OC - Oxidizing catalyst

(2)Reduction factor defined as: $\frac{\text{control system emissions}}{\text{1972 baseline emissions}}$ based on LA-4 driving cycle.

(3)All emissions data taken using or corrected to 1975 CVS-CH test procedure

(4)Deterioration of present systems; L = 10%, M = 10 - 30%, H = 30%

3.1.3.2 Gas Turbines

Although gas turbines contributed only an estimated 2.5 percent of the annual stationary source NO_x emissions in 1972, they comprise a very rapidly growing industry with increasing application in

- Intermediate and base load power generation
- Pipeline pumping
- Natural gas compressors
- On-site electrical generation

Combustion modification strategies for gas turbines differ from those of boilers since turbines operate at a lean A/F ratio with the stoichiometry determined primarily by the allowable turbine inlet air temperature. The turbine combustion zone is nearly adiabatic and flame cooling for NO_x control is achieved through dilution rather than radiation cooling. The majority of NO_x formation in gas turbines is believed to occur in the primary mixing zone, where locally hot stoichiometric flame conditions exist. The strategy to NO_x control in gas turbines is to alleviate the high temperature stoichiometric regions through improved premixing, primary zone mixing and downstream dilution.

Typical NO_x emissions from gas turbines are illustrated on Figures 3-1 and 3-2 for small and large units, respectively (Reference 3-19). Also imposed on these figures are the San Diego County standards for NO_x emissions for non-mobile units greater than 50 million Btu heat input: 75 ppm NO_x at 15 percent oxygen for liquid fuels and 42 ppm NO_x at 15 percent oxygen for gaseous fuels (Reference 3-20). As seen in the figures, very few units meet these standards in the uncontrolled state.

Combustion modifications for gas turbines are classified into wet and dry techniques of which only wet methods, i.e., water or steam injection, presently provide substantial reductions. As yet, no combination of dry methods has been successful in reducing emissions below a typical standard of 75 ppm NO_x at 15 percent oxygen. Presently available wet and dry methods for NO_x reduction are aimed at either reducing peak flame temperature or reducing residence time at peak flame temperatures or both. These techniques, along with their reduction potential and future prospects, are shown in Table 3-9.

Wet techniques, water or steam injection, are the most effective methods yet developed with reduction potentials as high as 90 percent for gas and 70 percent for oil fuels. With wet control, water or steam is introduced into the primary zone by either premixing with the fuel prior to injection into the combustion zone, by injection into the primary air stream, or by direct injection into the primary zone. The effectiveness of each method is strongly dependent on atomization efficiency and primary zone residence time. In the case of water injection, peak flame temperatures

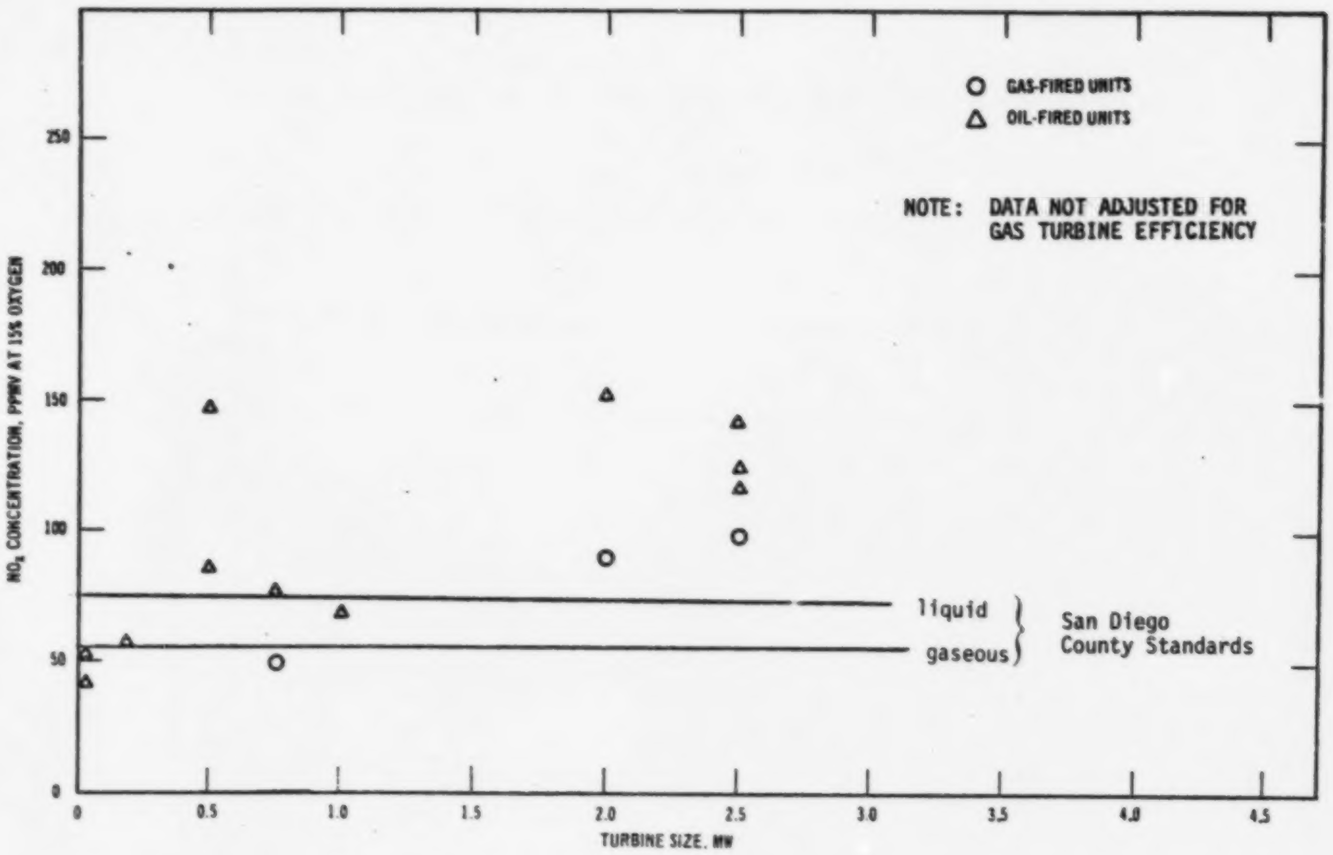

Figure 3-1. NO_x emissions from small gas turbines without NO_x controls. Reference 3-19.

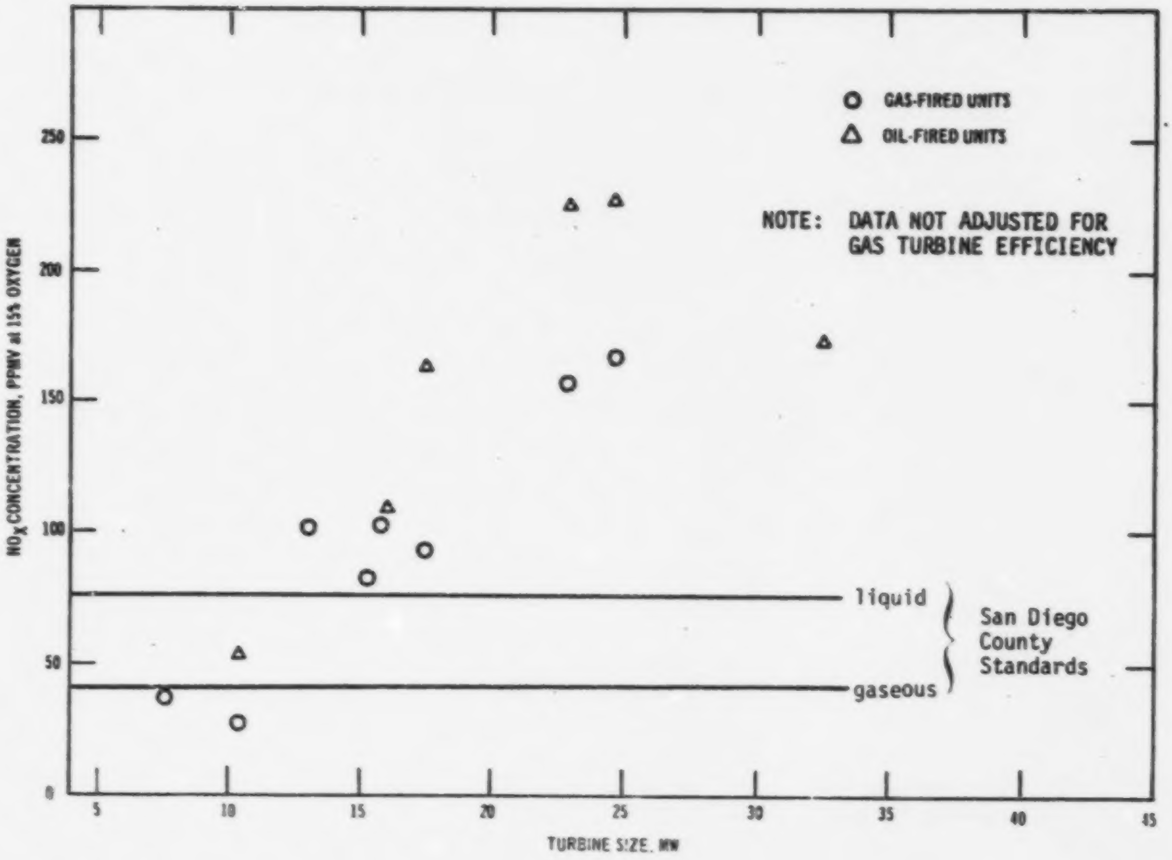

Figure 3-2. NO_x emissions from large gas turbines without NO_x controls, Reference 3-19.

TABLE 3-9. GAS TURBINE – SUMMARY OF EXISTING TECHNOLOGY – COMBUSTION MODIFICATIONS

Modification	Approach to NO_x Control	Reduction Potential	Near Term	Far Term	Additional Comments	Refs.
Wet Controls						
Water Injection	Lower peak flame temp by utilization of heat capacity and heat of vaporization	To 90% (50-70% oil) (60-90% gas)	To date, most effective measure and only which meets San Diego standard	Not seen as attractive long term solution, second priority to dry controls	Reduces efficiency, increases capital costs up to 10%. Operating costs as low as 1% depending on usage. Hindered by requirement for "clean" water supply. Ineffective in reducing fuel NO_x.	3-14 3-19 3-21 3-22
Steam Injection	Lower peak flame temp by utilization of heat capacity of steam	To 90% (50-70% oil) (60-90% gas)	To date, most effective measure and only which meets many San Diego standards	Like water injection, unattractive long term solution	Increases overall efficiency by increasing flowrate. Installation and operating costs same as water injection. Requires high pressure steam. Ineffective in reducing fuel NO_x.	
Methods of Injection				As noted above, all wet techniques are considered interim methods and will eventually yield to more effective, less expensive, more efficient dry methods	In all cases, the effectiveness is strongly dependent upon both atomization efficiency and primary zone residence time.	
Premix prior to injection into combustion zone						
Injecting into primary air stream						
Direct injection into primary zone						
Dry Controls						
Lean Out Primary Zone	lower peak flame temp	10-20%	Attractive option, requires additional controls to meet standards	Generally seen as an option to be incorporated into new low NO_x designs	Decrease in power output, less control over flame stabilization	3-14 3-19 3-22
Increase Mass Flowrate	Reduce residence time at peak temperatures	To 15%	Attractive option if feasible	Not an attractive long term option due to inflexibility	Increase in shaft speed constant torque	3-19
Earlier Quench with Secondary Air	Reduce residence time	To 15%	Minor combustor modification used presently with wet controls	An attractive concept to be employed in advanced combustors	An attractive option both for near term minor combustor modifications and for incorporation into new designs. Limited by flowrates and incomplete comustion	3-14 3-19 3-20

TABLE 3-9. (CONCLUDED)

Modification	Approach to NO_x Control	Reduction Potential	Near Term	Far Term	Additional Comments	Refs.
Air Blast or Air Assist Atomization	Reduce peak flame temp by increasing mixing thereby reducing local A/F ratio		Considered a minor combustor mod	Promising method to be incorporated into new low NO_x design	Generally considered a major retrofit.	3-19
Reduce Inlet Preheat (Regenerative)	Reduce peak flame temp		Not attractive due to thermal efficiency reduction	Not attractive for long term solution	Reduces efficiency.	3-19
Other Minor Combustor Modifications and Retrofit	Reduce peak flame temp through premixing, secondary air injection, primary zone flow recirculation	To 38% Combined	Attractive near term as an interim solution		In general reduces efficiency while reducing NO_x. Require additional controls and greater downtime.	3-19
Exhaust Gas Recirculation	Reduce peak flame temperatures	To 38%	Option has seen use in minor combustor modifications	An attractive option for future design with internal combustors	Reduced efficiency requires additional controls.	3-19

are reduced through the vaporization of the water and the relatively high heat capacity of steam. Steam injection reduces peak flame temperature by using only the heat capacity of steam. Although NO_x reduction is quite effective, numerous difficulties offer incentive to the development of dry controls. The future of wet control does not appear promising based on the following inherent problems:

- High capital and operating costs
- Requirements for "clean" water or high pressure steam
- Hardware requirements increase plant size
- Delivery system hardware resulting in increased failure potential and overhaul/maintenance time
- Uncertainty regarding long term control effects on turbine.

Although no combination of presently available dry controls has the reduction potential of the wet methods, many dry techniques are used in conjunction with water or steam injection, particularly on the larger units. On the smaller units, dry controls may be sufficient to meet standards. The dry controls now available are:

- Lean out primary zone — Reduces NO_x levels up to 20 percent by lowering peak flame temperatures. This option allows less control over flame stabilization and reduces power output but is an attractive control to be built into future low NO_x combustors.
- Increase mass flow rate — With possible NO_x reductions up to 15 percent, this control reduces residence time at peak flame temperature. This control essentially increases the turbine speed at constant torque and is not feasible in many applications.
- Earlier quench with secondary air — This is a minor combustor modification which entails upstream movement of the dilution holes to reduce residence time at peak termperatures. This is a promising control which is generally employed in advanced combustor research.
- Reduce inlet air preheat — A control applicable only to regenerative cycle units is not attractive due to reduction in efficiency.
- Air blast and air assist atomization — Use of high pressure air to improve atomization and mixing requires replacement of injectors and addition of high pressure air equipment. This control is considered an excellent candidate for incorporation into new low NO_x design combustors.
- Exhaust gas recirculation — With a possible NO_x reduction of 30 percent, EGR is a promising dry control for future design and has limited application in some on-line units. EGR requires extensive retrofit relative to other dry controls and also requires a distinct set of controls for the EGR system.

Other minor combustor modifications are generally aimed at improving favorable internal flow patterns in the primary zone and fuel/air premixing. The bulk of these modifications are combustor-specific and investigated by the manufacturer. In general, any combination of dry controls has not exceeded 40 percent NO_x reduction and as such are insufficient controls for the larger units. Since dry techniques approach NO_x reduction differently than do wet controls, their effects are additive and consequently frequently used together. Figures 3-3 and 3-4 illustrate the effect of dry and wet controls used separately and in combination for both liquid and gaseous fuels (Reference 3-19). The figures show dry controls to be inadequate to meet San Diego Standards where wet controls are sufficient while the combination is even more effective.

Future NO_x control in gas turbines is directed toward dry techniques with emphasis on combustor design. Medium term (1979-1985) combustor designs incorporate improved atomization methods or prevaporization and a premixing chamber prior to ignition. Favored techniques are a high degree of recirculation in the primary zone followed by rapid quenching with secondary air. These developmental combustors are projected to attain emission levels of 20 ppm NO_x at 15 percent oxygen.

3.1.4 Space Heating

Residential and commercial space heating contributes an estimated 7.1 percent of the total annual stationary source NO_x emissions. This figure is magnified by two important considerations: the bulk of these emissions are produced during the winter heating season and the majority of the units are located in or near urban areas. In addition to NO_x, several equally significant pollutants are generated by these units: carbon monoxide (CO), unburned hydrocarbons (HC), and smoke. Boilers for commercial heating range in size from 10 to 300 boiler horsepower (~0.35 to 10 M Btu/hr) while residential heaters range in capacity from 75,000 to 300,000 Btu/hr. Recent studies by Battelle (Reference 3-23) have determined typical emissions from these equipment groups. These are presented in Table 3-10. Although the variation of emission levels was found to be dependent upon boiler size, design, burner type, burner age, operating conditions, etc., the effect of fuel type was found to be of greatest importance as conversion of 40 to 60 percent of the fuel nitrogen to NO_x was indicated.

Presently available emission reduction techniques for space heating units are limited to

- Tuning — the best adjustment in terms of the smoke-CO_2 relationship that can be achieved by normal cleanup, nozzle replacement, simple sealing and adjustment with the benefit of field instruments.

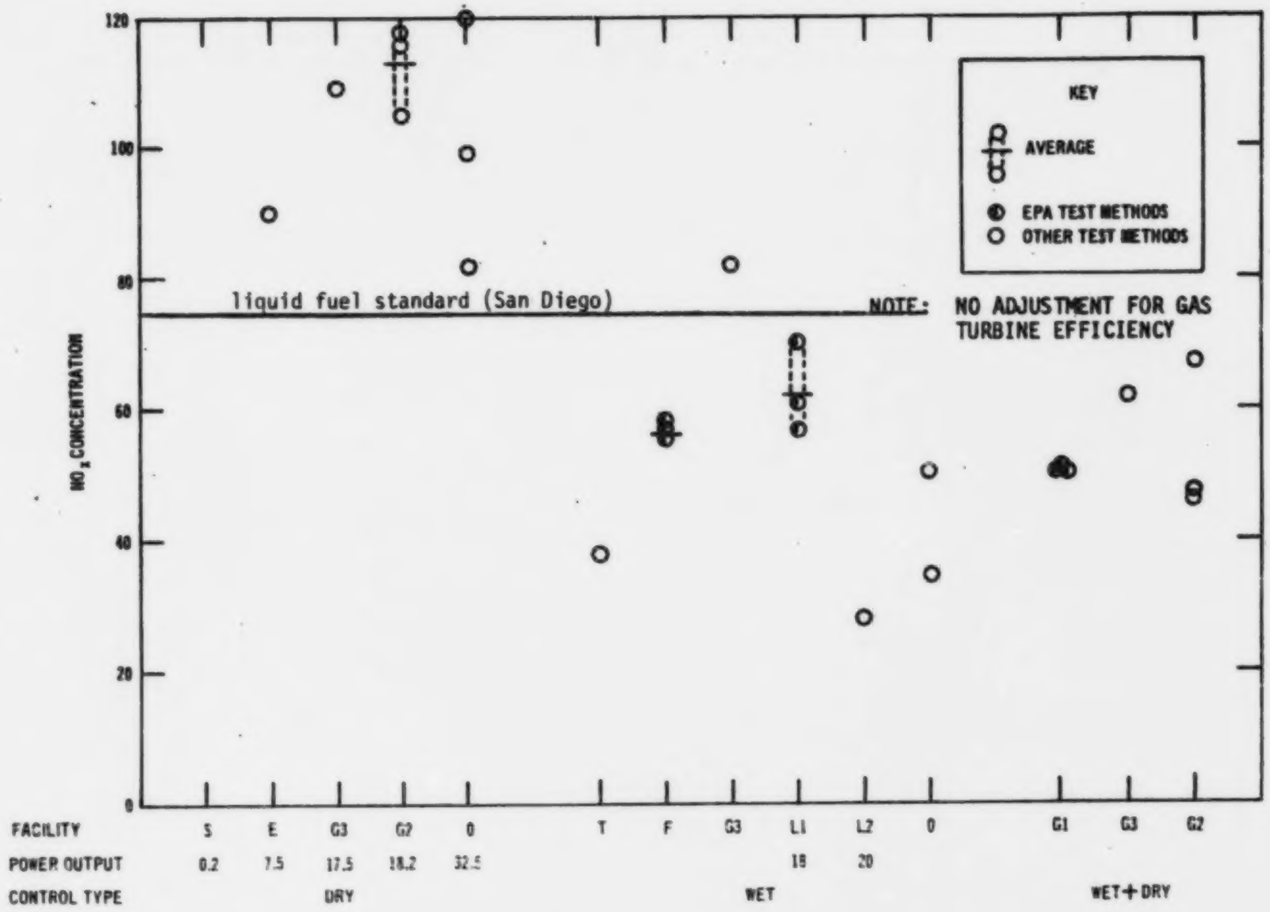

Figure 3-3. NO_x emissions from gas turbines having NO_x controls and operating on liquid fuels, Reference 3-19.

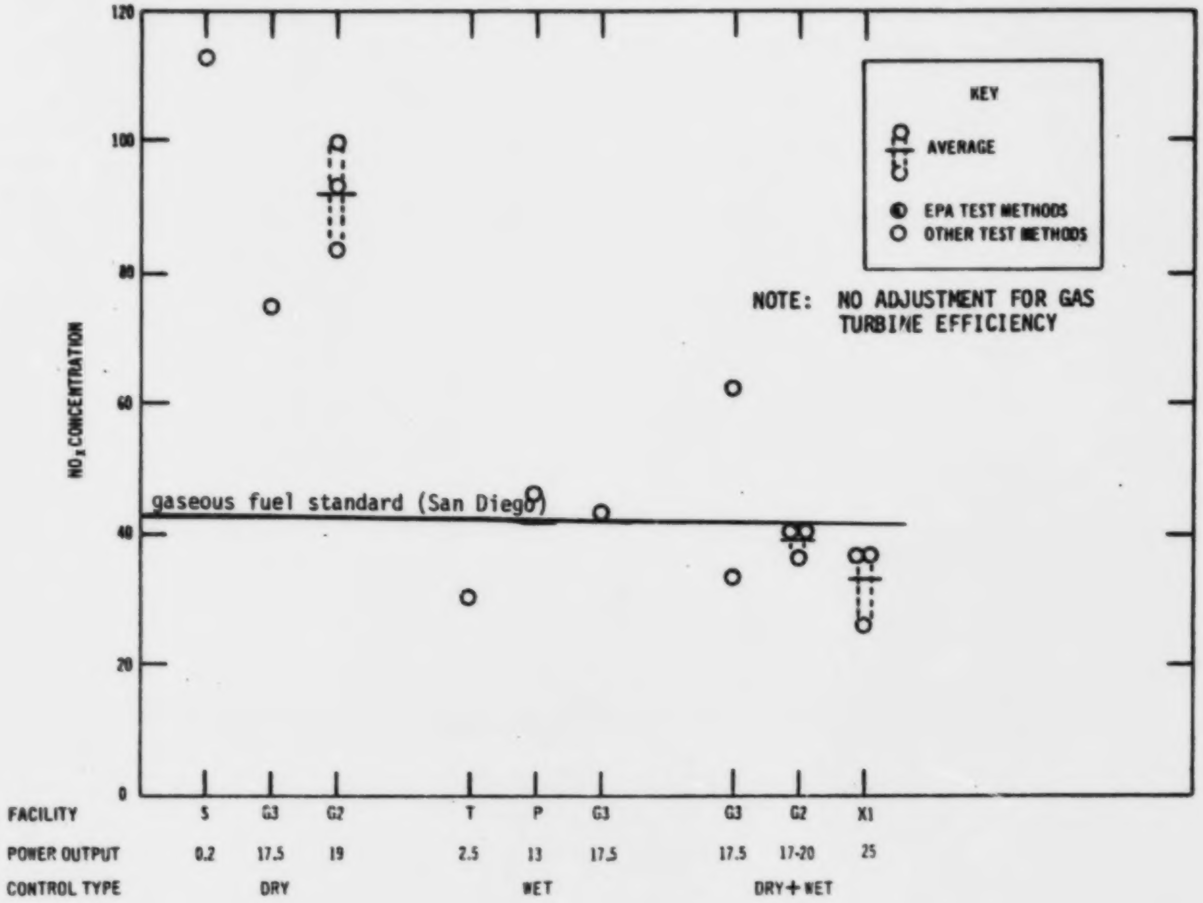

Figure 3-4. NO_x emissions from gas turbines having NO_x controls and operating on gaseous fuels, Reference 3-19.

TABLE 3-10. TYPICAL EMISSION LEVELS FROM COMMERCIAL AND RESIDENTIAL HEATING, REFERENCE 3-23.

Unit	Fuel	Emission Concentration @ 3% O_2, dry basis			
		NO_x as NO_2	CO	HC	Bacharach Smoke
Residential	Gas	70	15	3	0
Residential	No. 2 Oil	115	65	13	3.0
Commercial	Gas	80	20	9	0.2
Commercial	No. 2 Oil	100	4	3	0.9
Commercial	No. 4 Oil	390	7	3	2.6
Commercial	LSR*	260	3	5	2.9
Commercial	No. 5 Oil	290	16	4	3.0
Commercial	No. 6 Oil	415	10	5	3.9

*Low Sulfur Residual Oil (~1% S)

- Unit replacement — installation of a new, more advanced unit
- Burner replacement — installation of a new low-emission burner

The Battelle study indicates that the combination of tuning and unit replacement has a beneficial effect on all pollutants with the exception of NO_x. In the sampling, units considered in "poor" condition were replaced and all others were tuned, resulting in reductions in smoke, CO, HC and filterable particulate by 59, 81, 90 and 24 percent respectively, with no change in NO_x levels. This testing was carried out on oil-fired units only, but Hall (Reference 3-24) determined that gas-fired units exhibit emission levels similar to an equivalent size high pressure atomizing gun oil burner. Table 3-11 shows mean emission levels prior to and after replacement and tuning. Although tuning and replacement have been shown to have little effect on NO_x levels, yearly inspection accompanied by one of these techniques is highly recommended since other pollutant levels are so greatly reduced.

Significant emission reduction can be affected by burner replacement. Battelle found this procedure to produce significantly lower levels of CO and filterable particulate and slightly lower levels of HC and NO_x believed to be due only to improved burner designs. In general, recently developed burners have not demonstrated the ability to consistently reduce NO_x levels while many, in improving combustion efficiency and reducing other pollutant levels, actually increase NO_x emissions over the standard burner. A number of commercially available burners were tested by Hall (Reference 3-25) wherein pollutant levels were determined under operating conditions. Combustion-improving devices yielded higher NO_x levels than the standard, but demonstrated a potential for reducing levels of one or more pollutants and for improving combustion efficiency. Flame retention burners were shown to be capable of operating at low excess air levels, resulting in increased combustion efficiency with accompanied reduction in emission levels with the exception of NO_x. During this testing, one device was demonstrated to reduce NO_x levels appreciably. Although the reduction mechanism is unknown, further studies are underway to define critical parameters in burner design. Both the combustion improving devices and flame retention burners utilized the conventional high pressure atomizing gun nozzles. Several other experimental and commercially available burners not employing the high pressure atomization gun were tested. Of these, only the "blue flame" burners showed substantial NO_x reduction but also demonstrated higher than baseline levels of CO, HC and smoke. Future developments will include mechanisms for simultaneous reductions for all pollutants by way of advanced burner design and further development of integrated low-emission units for replacement and new installations. Present development by Rocketdyne (Reference 3-26) indicate progress into the prototype stages on the integrated unit.

By way of summary, the available means for reducing pollutant levels from residential and commercial space heating units do not consistently reduce NO_x levels

TABLE 3-11. COMPARISON OF MEAN EMISSIONS FOR CYCLIC RUNS ON RESIDENTIAL OIL-FIRED UNITS

Units	Condition	Units in Sample[a]	Mean Smoke No.[b]	Mean Emission Factors, lb/1000 gal			
				CO	HC	NO_x	Filterable Particulate
Mean Values From Phase I and II Battelle/API/EPA Investigation:							
All units	As-Found	32	(c)	>22.1	5.7	19.4	2.9
	Tuned	33	(c)	>16.4	3.0	19.5	2.3
All units, except those in need of replacement	As-Found	29	3.2	7.8	0.72	19.6	2.4
	Tuned	30	1.3	4.3	0.57	19.5	2.2

but are beneficial to CO, HC, smoke and filterable particulates. While tuning has no effect on NO_x levels, unit or burner replacement can demonstrate slight reductions due to more advanced design techniques.

3.2 FUEL MODIFICATION

Knowledge of the important role that the fuel plays in the formation of NO_x identifies fuel modification as an obvious NO_x reduction strategy. The major fuel modification options are fuel switching, denitrification, and use of fuel additives.

3.2.1 Fuel Switching

This method usually entails the conversion of the combustion system to the use of a fuel with a reduced nitrogen content (to suppress fuel NO_x) or to one that burns at a lower temperature (to reduce thermal NO_x). Sulfur control is usually a dominant cost incentive for fuel switching. Natural gas firing is an attractive NO_x control strategy because of the absence of fuel NO_x in addition to the flexibility it provides for the implementation of combustion modification techniques. Despite the superior cost-effectiveness of gas-fired NO_x control, the economic considerations in fuel selection are dominated by the current clean fuel shortage. Indeed, the trend is toward the use of coal for electric power generation and larger industrial processes. On a short-term basis, fuel switching to natural gas or low nitrogen oil is not a promising option.

A promising long-range option is the use of clean synthetic fuels derived from coal. Candidate fuels include lower Btu gas (100 to 800 Btu/scf) and synthetic oil. Process and economic evaluations of the use of these fuels for power generation are being performed by the United States EPA, ERDA, the American Gas Association, and the Electric Power Research Institute. Two alternatives for utilizing low and intermediate Btu gases are firing in a conventional boiler or in a combined gas and steam turbine power generation cycle. For both systems, economic considerations favor placement of both the gasifier and the power cycles at the coal minehead. The most extensive use of these systems would probably be for replacement of older conventional units upon their retirement.

The NO_x emissions from lower Btu gas-fired units are expected to be low due to reduced flame temperatures corresponding to the lower heating value of the fuel. The effects of NO_x formation of the molecular nitrogen and the intermediate fuel nitrogen compounds, such as ammonia, in the lower Btu gas have not yet been determined and require further study.

The feasibility of synthetic fuel firing as a NO_x control option is contingent on the cost tradeoff between synthetic fuel production and the total control costs for NO_x, SO_x and particulates in conventional coal firing. There is preliminary evidence that gasification may be more costly than flue gas cleaning of conventional systems (Reference 3-27).

3.2.2 Fuel Additives

In principle, additives to the fuel could reduce NO_x emissions through one or a combination of the following effects:

- Reduction of flame temperature through increased thermal radiation or dilution
- Catalytic reduction or decomposition of NO to N_2
- Reduction of local concentrations of atomic oxygen

In 1971, Martin, et al., tested 206 fuel additives in an oil-fired experimental furnace, and 4 additives in an oil-fired packaged boiler. None of the additives tested reduced NO emissions but some additives containing nitrogen increased NO formation (Reference 3-28).

In another investigation of fuel additives, Shaw tested 70 additives in a gas turbine combustor and found that only metallic compounds that promoted the catalytic decomposition of NO to N_2 had a significant effect on NO emissions. Average reductions of 15 to 30 percent were achieved with the addition of 0.5 percent (by weight) of iron, cobalt, manganese, and copper compounds. The use of these additives for controlling NO_x is not attractive, however, due to added cost, serious operational difficulties and the presence of the additives, as a pollutant, in the exhaust gas (Reference 3-29).

An indirect reduction of NO_x could result from the use of additive metals intended to prevent boiler tube fouling. The excess air level in oil-fired boilers is frequently set sufficiently high to prevent tube fouling. Use of additives could allow the lowering of excess air levels which in turn would reduce NO_x formation. The emission reduction from this method, however, is quite limited and the cost-effectiveness is likely to be poor (References 3-30 and 3-31).

3.2.3 Fuel Denitrification

Fuel denitrification of coal or heavy oils could in principle be used to control the components of NO_x emission due to conversion of fuel bound nitrogen. The most likely use of this concept would be to supplement combustion modifications implemented for thermal NO_x control. Current technology for denitrification is limited to the side benefits of fuel pretreatment to remove other pollutants. There is preliminary data to indicate that marginal reductions in fuel nitrogen result from oil desulfurization (Reference 3-32) and from chemical cleaning or solvent refining of coal for ash and sulfur removal (Reference 3-33). The low denitrification efficiency of these processes does not make them attractive solely on the basis of NO_x control. They may prove cost effective, however, on the basis of total environmental impact.

3.3 ALTERNATE PROCESSES

For new combustion systems, the combustion control technology derived from retrofit of existing units can be incorporated, together with new concepts not applicable for retrofit, into designs optimized for low NO_x production. The flexibility of this approach yields potentially lower costs and higher effectiveness relative to retrofitting existing units. Alternatively, the economics of the utilization of lower quality fuels necessitated by the clean fuels shortage may dictate the selection of alternate combustion process concepts.

The most popular alternate concepts appear to be fluidized bed combustion and catalytic combustion, both of which are currently being investigated by various agencies and organizations. These processes are described briefly below.

3.3.1 Fluidized Bed Combustion

Suggested advantages of fluidized bed combustion compared to conventional boilers are:

- Compact size yielding low capital cost, modular construction, factory assembly, and low heat transfer area
- Higher thermal efficiency yielding lower thermal pollution
- Lower combustion temperature (1400°F to 1800°F) yielding less fouling and corrosion
- Potentially efficient sulfur control
- Applicable to a wide range of low-grade fuels including char from synthetic fuels processes
- Adaptable to a high efficiency gas-steam turbine combined power generation cycle (References 3-34, 3-35 and 3-36)

The feasibility of the FBC for power generation depends in part on the following: development of efficient methods for regeneration and recycling of the dolomite/limestone materials used for sulfur absorption and removal; obtaining complete combustion through flyash recycle or an effective carbon burnup cell; development of a hot-gas particulate removal process to permit use of the combustion products in a combined-cycle gas turbine without excessive blade erosion.

The potential for reduced NO_x emissions with fluidized bed combustion is currently under investigation in several EPA-funded projects. Preliminary tests with pilot scale units indicate that emission levels well within the EPA standard of

0.7 lb $NO_2/10^6$ Btu for new coal-fired units can be achieved (References 3-34 and 3-35). At the operational temperatures of the fluidized bed, the rate of formation of thermal NO_x is very low and nearly all NO_x emitted results from conversion of fuel nitrogen. The fuel nitrogen content in the coals used in the pilot tests was not given, so these results cannot be generalized.

Several of the pilot scale units have been tested for the effects of operational variables on NO_x emissions. BCURA has reported preliminary evidence that their pressurized fluidized bed yields lower emissions than their atmospheric unit (Reference 3-36). The bed temperature has little effect on NO_x emissions in the range from 1400°F to 1800°F, but operation with excess air increases NO_x significantly. Argonne and Exxon have suggested that operation with two-stage combustion may be effective for NO_x control in the firing of high nitrogen content coals (References 3-35 and 3-37). Exxon suggests that two-stage combustion could have the additional advantage of increasing the efficiency of the sulfur removal process.

From a NO_x control standpoint, fluidized bed combustion is regarded as a medium risk concept because the economic feasibility of the basic process and NO_x control techniques have not been fully established relative to conventional boilers or low Btu gas combined-cycle units.

3.3.2 Catalytic Combustion

Catalytic combustion refers to those concepts in which combustion occurs in close proximity to a solid surface. The interest in the concept arises from the low pollutant emission characteristics, in particular NO_x, which result from the combustion process occurring at reduced temperatures. In the catalytic combustor, reduced combustion temperatures are achieved by operation with very lean or very rich fuel/air mixtures, or by high heat transfer from the catalyst surface. The catalyst promotes chemical reactions, which, at the catalyst temperature (1600°F to 2000°F) would otherwise proceed too slowly for sustained combustion. Combustion is usually supported on a porous ceramic plate, and radiation is the dominant heat transfer mechanism.

Collection of background information and an assessment of the applicability of catalytic combustion concepts to gas turbines and utility boilers was performed by the Aerospace Corporation (Reference 3-38). This report concluded that catalytic concepts may be applicable to gas turbines, but that a retrofit to a utility boiler was impractical. The report also indicated that only gases and light, sulfur-free hydrocarbon liquids are appropriate as catalytic combustion fuels, due to system requirements and catalyst poisoning potentials.

An ongoing EPA effort has as its goal the assessment of the feasibility of applying catalytic concepts to area sources, including industrial boilers, commercial and residential heating systems, and industrial process heating units. The compilation of information on all aspects of this program, including fuels and equipment characterization and trade-off analyses between retrofit and new design strategies, is currently being performed under several EPA-sponsored programs. Catalytic combustion is a promising long-term concept for clean fuel combustion in area sources, but much research and development work must be done before it becomes commercially available on a wide scale.

3.4 FLUE GAS TREATMENT OF NO_x

There exists to date no fully developed flue gas treatment process for controlling nitrogen oxides. However, several potential candidate processes do exist, but which have not been adequately demonstrated on a coal-fired boiler as yet. Many of these candidate processes remove both SO_2 and NO_x:

- The Shell/UOP CuO adsorption process, in addition to removing SO_2, has been found to remove approximately 60 to 70 percent of the nitrogen oxides as well. This process has been successfully demonstrated on several oil-fired units, and is currently being tested on a slipstream from a coal-fired boiler (Reference 3-39)
- The Chiyoda Thoroughbred 102 process is similar to the 101 desulfurization process, except that now both SO_2 and NO_x are removed in a single absorber after the NO is oxidized to NO_2. At the present time, research on the 102 process is being conducted with bench scale and pilot plants, whereas the 101 process has been successfully demonstrated on many oil-fired units throughout Japan (Reference 3-40).
- The Bergbau-Forschung/Foster Wheeler process utilizes a char adsorption system for SO_2 removal and simultaneously removes a maximum of about 50 percent of the NO_x. A pilot plant unit on a coal-fired boiler in West Germany was in operation from 1968 to 1970, and a demonstration unit is currently under construction on a coal-fired boiler in the United States (Reference 3-41).

A number of SO_2 wet scrubbing processes (e.g., lime/limestone, magnesia, sodium carbonate) have also been shown to remove a small portion (generally about 10 percent and usually never more than 20 percent) of the NO_x from power plant flue gases; however, these processes cannot be considered as primary flue gas treatment systems for NO_x control.

Several other candidate processes, not included in the above categories, also appear to be technically feasible NO_x control methods. Most of these are catalytic processes which are still in the early stages of research and development. Work on these process schemes has been confined to either laboratory or pilot scale studies, and has not included work on coal-fired units as yet. Many of these processes are discussed in a report by TRW (Reference 3-42). Some of these are described below.

- Various compounds have shown some potential for catalytic decomposition of NO_x to nitrogen and oxygen, but they have not been tested on actual power plant flue gases as yet. A major concern with this scheme is finding an efficient catalyst which remains effective under actual operating conditions.
- Two pilot plant studies on the selective catalytic reduction of NO_x by ammonia are currently underway in Japan and in the United States. Laboratory studies indicate that noble metal catalysts are "poisoned" by SO_x, while non-noble metal catalysts are efficient only at very high temperatures. Preliminary results from the pilot plant work show that 90 percent NO_x removal can be achieved with some noble metal catalysts and SO_2-free flue gas.
- Non-selective catalytic reduction appears to be a potential candidate only for simultaneous NO_x-SO_x abatement. Several possible process schemes have been proposed with either hydrogen, carbon monoxide or hydrocarbons as reductants, and one pilot plant scale study has been conducted in Japan with good results. High temperatures, however, are needed here for the catalysts to be effective, and several hazardous compounds have been identified as by-products from some of the process schemes.

Another NO_x flue gas treatment process involves the use of molecular sieves. However, since water does interfere in the absorption process, molecular sieves cannot be used to clean combustion generated pollutants but can and have been used to remove NO_x from tail gases from non-combustion sources, namely nitric acid plants.

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SECTION 4

COSTS OF NO_X CONTROL METHODS

The previous section briefly described the major techniques for controlling NO_X emissions from stationary sources. Of the three possible NO_X reduction strategies, precombustion, post-combustion, and combustion control, the latter has proven to be the most effective by both research programs and practical demonstrations. A number of classical combustion control techniques are currently available for use on a wide variety of stationary sources. The choice between these options will be based both on NO_X suppression success and added cost. The former topic has been extensively treated in this and other studies. The costs incurred by such controls, however, have been less well reported. The cost of implementing combustion modification techniques is basically the sum of the initial capital cost, annual capital cost, and annual operating cost (which includes any cost savings). This section of the report will summarize available information on the economics of these control methods, and identify areas where such data is lacking.

4.1 UTILITY BOILERS

The following discussion will center on the costs of reducing NO_X from utility boilers by combustion modification. To put such costs in perspective, the economics of flue gas treatment methods for the removal of NO_X and SO_X are also presented.

4.1.1 Costs of NO_X Control by Combustion Modification

Much of the pioneering work on evaluating the cost effectiveness of combustion modification in full-scale combustion equipment has been performed on utility boilers. Correspondingly, the related costs of these modifications have been, relative to other source types, fairly well documented for this sector. One of the earliest efforts of this kind was attempted by Esso Research Labs in 1969 (Reference 4-1). Based on estimates for the capital, annual, and operating costs, the Esso report presented the results of a cost effectiveness study peformed for NO_X control on utility boilers by means of combustion modification. Since 1969, however, it has been revealed that a wide variation in the effectiveness of the control techniques among boilers exists. This problem will require that future cost-effectiveness evaluations be done on an individual boiler basis.

Data from Combustion Engineering

The most recent cost data were published by Blakeslee (Reference 4-2) for new and existing tangential, coal-fired utility boilers. These data are summarized in

Figures 4-1 and 4-2. The cost range curves were derived from estimates developed under an EPA-sponsored contract involving the reduction of NO_x from both new and existing tangentially, coal-fired utility boilers.

Four possible methods for reducing NO_x emission levels were evaluated. These included overfire air, gas recirculation to the secondary air ducts, gas recirculation to the coal pulverizer/primary air system and furnace water injection. The cost trends for these methods were projected over a unit size range of 125 to 750 MW.

Two levels of cost are established. The first is for new unit designs, Figure 4-1, with heating surfaces adjusted to compensate for the resultant changes in heat transfer distribution and rates. The second level of cost, Figure 4-2, applies to existing units with no change in heating surface as these changes must be calculated on an individual unit basis. For both cases, the costs shown are in 1973 dollars, and except where otherwise noted are estimated on a ± 10 percent basis.

It is readily observed that the cost ranges for existing units vary more widely than for new units. This is due to the variations in unit design and construction which can either hinder or aid the installation of a given NO_x control system.

At approximately 60 MW, single cell-fired boilers reach a practical size limit and divided furnace designs are utilized. As a divided tangentially-fired furnace has double the firing corners of a single cell furnace, the costs increase significantly. It should be kept in mind that although these cost data for utility boilers were developed for tangentially coal-fired boilers, it is felt that the range of costs presented should be generally applicable to wall-fired boilers burning coal. Additionally, it is intuitively felt that the cost for similar combustion modification on gas and oil-fired utility boilers should be no higher than for the coal-fired units.

The cost of reducing low excess air was not investigated since there is generally no significant additional cost for modern units or units in good condition. However, some older units may require modifications such as altering the windbox by addition of division plates, separate dampers and operators, fuel valving, air register operators, instrumentation for fuel and air flow and automatic combustion controls.

Data from EPA

Table 4-1 shows estimated investment costs for low excess air (LEA) firing on utility boilers requiring modifications (Reference 4-4). These costs can vary depending on the actual extent of the required modification and are only provided as guidelines. As unit size increases, the cost per KW decreases since the larger units typically have inherently greater flexibility and may require less extensive modification.

The use of low excess air firing reportedly increases boiler efficiency by 0.5 to 2 percent, in addition to savings resulting from decreased maintenance and operating costs. Consequently, any investment costs can be offset in fuel and operating expenses.

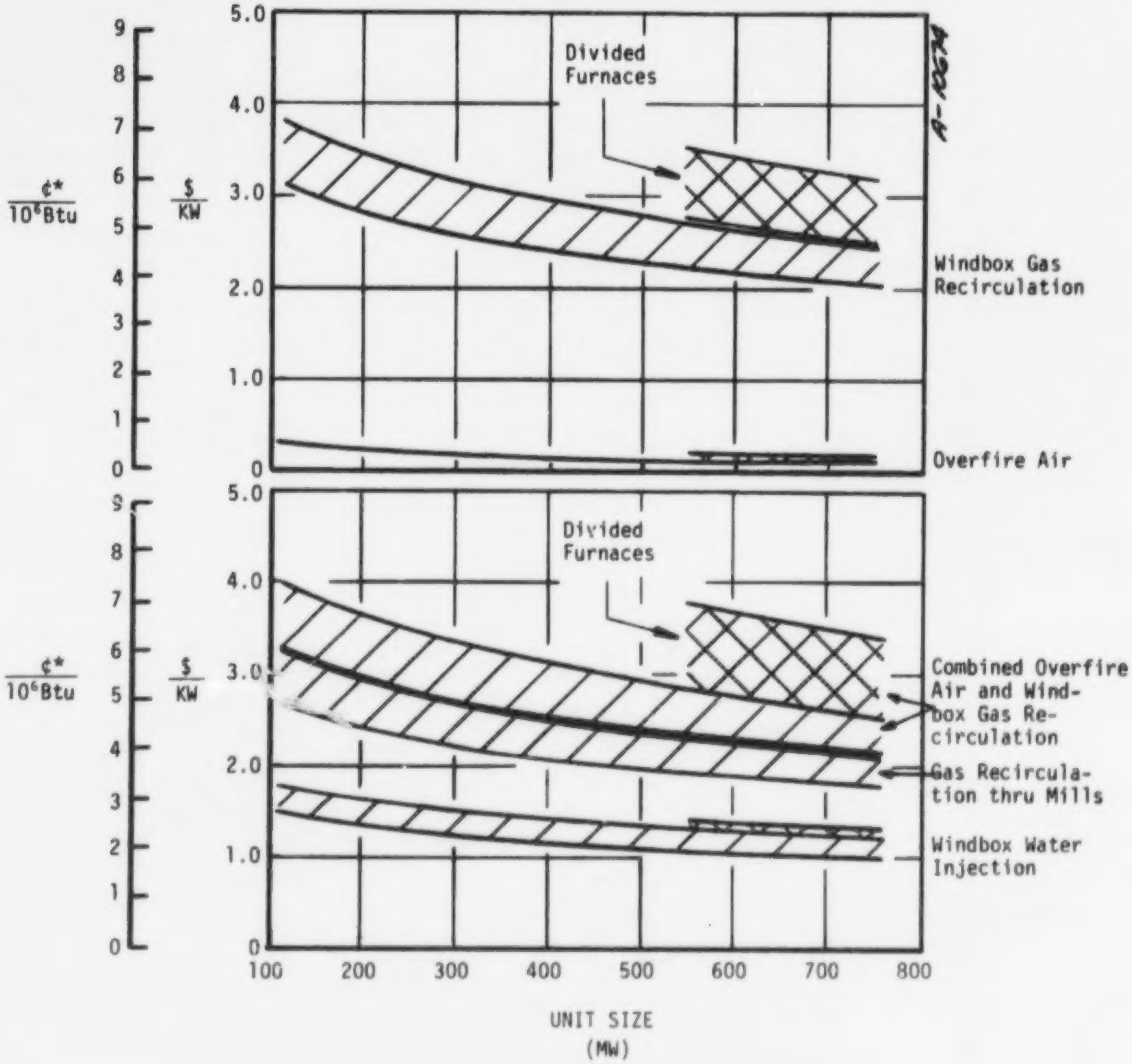

Figure 4-1. 1973 installed equipment costs of NO_x control methods for new tangentially, coal-fired units (included in initial design).

*Based on: 5400 hrs/yr at rated MW and net plant heat rate of 10^4 Btu/KWhr (Reference 4-3).

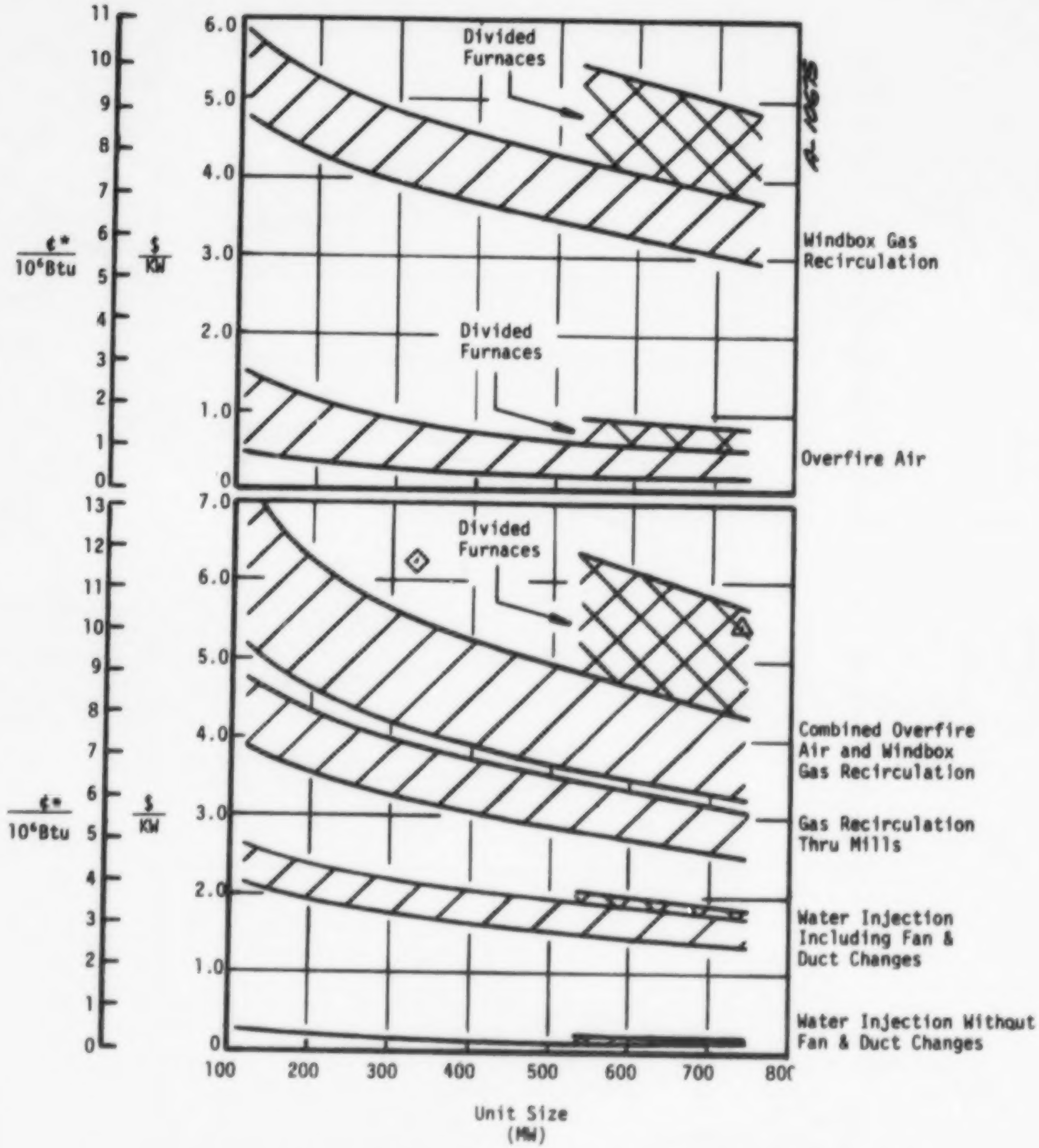

Figure 4-2. 1973 installed equipment costs of NO_x control methods for existing tangentially, coal-fired units (heating surface changes not included).

△ PG&E Portrero #3

◇ PG&E Pittsburg #7

*Based on 5400 hrs/yr at rated MW and net plant heat rate of 10^4 Btu/kwhr (Reference 4-2).

TABLE 4-1. 1974 ESTIMATED INVESTMENT COSTS FOR LOW EXCESS AIR FIRING ON EXISTING BOILERS NEEDING MODIFICATIONS

Unit Size (MW)	Investment Cost ($/KW)	
	Gas and Oil	Coal
1000	0.12	0.48
750	0.16	0.51
500	0.21	0.55
250	0.33	0.64
120	0.53	0.73

Data from the Pacific Gas and Electric Co.

As an example of the manner in which the costs for combustion modification may vary among individual existing units, several case studies are presented in Table 4-2. The figures shown are the costs incurred by the Pacific Gas and Electric Company during a program to bring six units into compliance with local NO_x emission regulations. For the most part, the conversions involved the combination of windbox flue gas recirculation and overfire air ports (Reference 4-5). These data are plotted on Figure 4-2. It is observed that the points lie somewhat above the appropriate band of costs. The one-year difference between the base costing years is a partial explanation for this lack of correlation.

Data from the Los Angeles Department of Water and Power

Another West Coast electric utility company, the Los Angeles Department of Water and Power (LADWP), has had extensive experience in implementing NO_x control techniques on its gas and oil-fired boilers. The techniques currently utilized by the Department include the biased firing, or "burners out of service" (BOOS) method, overfire air/NO_x ports, and low excess air. The use of the latter technique, when combined with BOOS or overfire air, is limited. Although the units are operated with the lowest excess air possible, it has been found that when LEA is combined with other reduction methods, excess air levels must be increased beyond those normally required.

The Department's data indicate a unit efficiency decrease of approximately one percent attributable to BOOS operation. As has been found by other operators, LEA tended to increase efficiency slightly: a one percent decrease in excess oxygen increased efficiency by about 0.25 percent. Properly retrofitted, overfire air had no effect on efficiency.

The NO_x control costs incurred by LADWP are shown in Table 4-3 for four different units. The figures for the BOOS techniques reflect the R&D costs that necessarily precede the retrofit. All costs include the labor required to implement the control methods, and are, therefore, installed equipment costs. The very low expense associated with overfire air on the B&W 235 MW unit is due to the base year of the estimate (1964 – 1965) and to the fact that this modification was included in the original boiler design.

The overfire air costs for the B&W 350 MW unit lie in the low range of the appropriate band of costs in Figure 4-2. The LADWP boilers were, for the most part, modified without much difficulty, and the associated costs probably represent the lower limits of the costs for the three NO_x reduction techniques implemented (Reference 4-6).

Data from the Babcock and Wilcox Co.

An additional indication that including NO_x controls on newly designed units is more economical than installing them on existing units comes from the Babcock and Wilcox Company. Their designers have estimated that NO_x control-related equipment (FGR and overfire air ports) will account for about $2 of the total boiler cost per KW (Reference 4-7).

TABLE 4-2. 1974 INSTALLED EQUIPMENT COSTS FOR EXISTING RESIDUAL OIL-FIRED UTILITY BOILERS

Unit Name	Design Type	Year on-Line	Capacity (MW)	Modification Cost ($$10^6$)	$/KW	Type of Modification
Pittsburg #7	CE Tangentially-fired, divided	1972	735	4	5.4	Windbox FGR, Overfire Air • 2 new 5000 HP FGR fans • FGR ducting • NO_x port installation • No new burner safeguard system; existing computerized O_2 system
Pittsburg #5 and #6	B&W Opposed-fired	1964	330(each)	5.6(both)	8.5	Windbox FGR, Overfire Air • Transferred two FGR fans from other units • FGR ducting • New hopper • NO_x port installation; one for each burner column • New burner safeguard system: computer, NO_x control board, O_2 controls on dampers, flame scanners
Contra Costa #6 and #7	B&W Opposed-fired	1965	330(each)	4.112(both)	6.2	Windbox FGR, Overfire Air • New FGR fans (one each) • Nominal amount of new ducting to windbox • NO_x port installation
Portrero #3	Riley Turbo-fired	1972	300	2.5	8.3	Windbox FGR, Overfire Air • New FGR fan • NO_x port installation, nominal amount of ducting • New burner safeguard system, NO_x control board, computer

TABLE 4-3. LADWP ESTIMATED INSTALLED 1973 CAPITAL COSTS FOR NO_x REDUCTION TECHNIQUES ON GAS AND OIL-FIRED UTILITY BOILERS

Unit Capacity (MW)	Unit Type	NO_x Reduction Technique	Implementation Method	Estimated Cost ($)	$/KW
180	C.E. tangentially-fired	BOOS	Retrofit	60,000	0.33
		LEA	Retrofit	25,000	0.14
235	C.E. tangentially-fired	BOOS	Retrofit	65,000	0.28
		LEA	Retrofit	25,000	0.11
235	B&W Opposed-fired	BOOS	Retrofit	65,000	0.28
		Overfire air	Original Design	14,000*	0.06
		LEA	Retrofit	25,000	0.11
350	B&W Opposed-fired	BOOS	Retrofit	230,000	0.66
		Overfire Air	Retrofit	87,000	0.25
		LEA	Retrofit	25,000	0.07

*1964-65 base year

Operating Cost Data

In addition to the increased capital costs resulting from including a NO_x reduction system in a unit design, the increased unit operating costs must be considered. These differential operating costs were defined for 100, 450, and 750 MW new design units and are shown in Table 4-4 (Reference 4-2). The equipment costs shown are determined from Figure 4-1. It should be noted that although the total annual cost increases with boiler size, the operating cost on a KWHR basis declines.

To put these operating costs in perspective, they can be compared to the "average" generating costs shown in at the bottom of Table 4-4. Except for the case of water injection, the differential in operating cost is below one percent even for flue gas recirculation.

Again, inflation factors must be applied to this 1973 cost data to bring it up to date. Although the variance in coal price is wider at present than ever before, a reasonable average value is taken to be $1.00/$10^6$ Btu. This causes a commensurate increase in the additional annual fuel cost for water injection (Reference 4-8).

Summary

By way of summary, Table 4-5 gives the impact on major system components, efficiency, and capacity when employing the major NO_X control techniques. The relative changes in unit design or efficiency are shown to increase (or require addition) by a plus (+) or a decrease (-). If the item is unchanged, or is altered to a negligible extent, it is indicated by a zero (0). Heat transfer surfaces remain unchanged in all cases (Reference 4-4).

The following are the major economic considerations that the boiler operator or designer may be faced with (Reference 4-2):

- The lowest cost method for reducing NO_X emission levels on new and existing units is the incorporation of an overfire air system. Minimal additional costs are involved.
- For most utility boilers, the second lowest cost NO_X control method appears to be the biased firing, or the "burners out of service" technique (BOOS). Although lowering excess air (LEA) alone is less expensive than BOOS, one utility company has found that when LEA is implemented concurrently with other control techniques, the excess air levels must be increased beyond those normally required.
- Gas recirculation is significantly more costly to implement than overfire air and requires additional fan power. In existing units, the necessity to reduce unit capacity to maintain acceptable gas velocities through the boiler convective sections may impose an additional penalty.
- For coal-fired units, gas recirculation to the coal pulverizers would cost approximately 15 percent less than windbox FGR; however, this may require increased excess air to maintain adequate combustion. FGR is not particularly effective in reducing NO_X from coal-fired systems.

TABLE 4-4. 1973 DIFFERENTIAL OPERATING COSTS OF NO_x CONTROL METHODS FOR NEW TANGENTIALLY, COAL-FIRED UNITS (SINGLE FURNACE)

Control Method		Overfire Air (20%)			Windbox Flue Gas Recirc. (30%)			Combination of 1 and 2			Coal Mill Flue Gas Recirc. (17%)			Water Injection		
MW Rating		100	450	750	100	450	750	100	450	750	100	450	750	100	450	750
Equipment Costs[a]	10^3\$	31	63	90	350	1185	1650	375	1248	1800	300	1015	1425	160	560	825
Annual Fixed Charge[b]	10^3\$	5	10	14	56	190	264	60	200	288	48	162	228	26	90	132
Additional Annual Fuel Cost[c]	10^3\$	---	---	---	---	---	---	---	---	---	---	---	---	147	660	1099
Additional Annual Fan Power Cost[d]	10^3\$	---	---	---	21	95	158	21	95	158	22	100	166	13	58	97
Total Annual Cost[e]	10^3\$	5	10	14	77	285	422	81	295	446	70	262	394	186	808	1328
Operating Cost	Mills/KWHR[f]	0.009	0.004	0.003	0.143	0.117	0.104	0.150	0.121	0.110	0.130	0.108	0.097	0.344	0.332	0.327[g]

Notes:

[a] Delivered and erected equipment costs (± 10% accuracy). Excluding contingency and interest during construction.

[b] 5400 HR/YR at rated MW and net plant heat rate of 9400 Btu/KWHR

[c] 50¢/10^6Btu coal cost.

[d] \$250/HP fan power cost, or \$40/HP per year.

[e] Annual fixed charge rate of 16%.

[f] Operating costs are ± 10%.

[g] Does not include cost of water piping in plant or cost of makeup water.

Base unit operating costs* for coal fired power plants excluding SO_2 removal systems.

Unit Size	MW	100	450	750
Operating Cost	MILLS/KWHR	16.2	13.5	12.6

*Includes 1973 Capital costs, labor, maintenance, fuel costs +20% contingency + 17% interest during construction.

TABLE 4-5. IMPACT OF NO_X CONTROL TECHNIQUES ON MAJOR UTILITY BOILER COMPONENTS

System Component	New Unit Design					Existing Units				
	O.A.[a]	Sec. FGR[b]	a+b	Prim. FGR[c]	Water Inj.[d]	O.A.[a]	Sec. FGR[b]	a+b	Prim. FGR[c]	Water Inj.[d]
Forced Draft Fan Size	+	0	+	+	0 or +	0 or +	0	0 or +	+	0
Secondary Air Ducts	0	+	+	0	0	0	+	+	0	0
Windbox Size	0	+	+	+	0	0 or +	+	+	+	0
FGR Fan	N/A[e]	+	+	+	N/A	N/A	+	+	+	N/A
FGR Ducts	N/A	+	+	+	N/A	N/A	+	+	+	N/A
Dust Collectors	0	+	+	+	0	0	+	+	+	0
Coal Pulverizers	0	0	0	0	0	0 or +	0	0 or +	0	0
Convective Surface	0	+	+	+	+	N/A	N/A	N/A	N/A	N/A
Superheat Surface	0	-	-	-	-	N/A	N/A	N/A	N/A	N/A
Reheat Surface	-	-	-	-	-	N/A	N/A	N/A	N/A	N/A
Economizer Surface	0	+	+	+	+	N/A	N/A	N/A	N/A	N/A
Boiler Efficiency[f]	0	0	0	0	-	0	0	0	0	-
Capacity	0	0	0	0	0	0	-	-	-	-

a. Overfire air system
b. Flue gas recirculation through the secondary air duct and windbox compartments
c. Flue gas recirculation to the transport air (primary air) of the coal pulverizers (mils)
d. Water injection to the firing zone
e. Not applicable
f. Average heat rate, Btu/KWH

- Water injection involves low initial equipment costs, but due to high operating costs resulting from losses in unit efficiencies, it is the least desirable of the systems evaluated. This method may also require reduced capacity.
- In general, the cost of applying any of the control methods to an existing unit will be approximately twice that of a new unit design.
- Attention must be given to the base year in which control cost estimates were made. The most recent figures on comparative electric power equipment costs from the Marshall and Swift Equipment Cost Index (1974) indicate that such costs have increased 19 percent from 1972 and 16 percent from 1973. It is safely estimated that such costs will be correspondingly higher in 1975.

4.1.2 Costs of SO_2 Control by Flue Gas Treatment

Tables 4-6 and 4-7 contain capital and operating costs for five SO_2 control processes — lime slurry scrubbing, limestone slurry scrubbing, magnesia scrubbing, sodium carbonate scrubbing and catalytic oxidation (Reference 4-9). These five processes represent the most advanced technology to date and have been proposed as the initial systems for full scale installation. The effect of varying the sulfur content of the fuel on estimated costs is relatively small. For an increase (or decrease) of one percent in the sulfur content of the fuel, one must add (or subtract) 3-7 $/KW to the capital costs in Table 4-6 and 0.1 - 0.5 mils/KWHR to the operating costs in Table 4-8 (except for the catalytic oxidation process, where these incremental capital and operating costs are negligible).

It is instructive to compare these SO_2 control costs to the previously discussed costs for control of NO_x by combustion modification techniques. Figures 4-1 and 4-2 show that the installed equipment costs incurred by implementing NO_x reduction techniques are, for the most part, an order of magnitude less than the costs of flue gas SO_x removal equipment. A similar difference appears between operating costs (Table 4-4 vs. Table 4-7). The major portion of the high SO_2 control system operating cost is the 15 percent of the total capital investment as part of the annual indirect costs.

The estimated costs of other developed SO_2 control processes are comparable to those shown in Tables 4-6 and 4-7. However, those processes which were found to be less effective in removing sulfur oxides from flue gases or whose costs were estimated to be prohibitively high are not included there. Possible future candidate processes (e.g., the Shell/UOP process, the Chiyoda Thoroughbred 101 process, the Bergbau-Forschung process) appear to have estimated costs somewhere in the range of costs given in Tables 4-6 and 4-7; however, these candidate processes are still under development and have not as yet been fully demonstrated on coal-fired boilers.

4.1.3 Costs of NO_x Control by Flue Gas Treatment

Since most of the processes discussed in Section 3.4 are still in the early stages of development, definitive costs are not available; however, preliminary cost estimates indicate

TABLE 4-6. 1975[a] INSTALLED EQUIPMENT COSTS FOR UTILITY BOILER FLUE GAS SO_2 REMOVAL

Unit Type	Unit Size (MW)	Lime Slurry Scrubbing[b]		Limestone Slurry Scrubbing[b]		Magnesia Scrubbing[b]		Sodium Carbonate Scrubbing[b]		Catalytic Oxidation[b]	
		$/KW	$/10⁶Btu[c]	$/KW	$/10⁶Btu[c]	$/KW	$/10⁶Btu[c]	$/KW	$/10⁶Btu[c]	$/KW	$/10⁶Btu[c]
Coal-fired new units (3.5% S in coal)	200	74	1.37	81	1.50	89	1.65	101	1.87	123	2.28
	500	56	1.04	63	1.17	66	1.22	76	1.41	108	2.00
	1000	41	.76	48	.89	49	.91	58	1.07	88	1.63
Coal-fired existing units (3.5% S in coal)	200	81	1.50	71	1.31	90	1.67	108	2.00	111	2.06
	500	65	1.20	58	1.07	65	1.20	78	1.44	95	1.76
	1000	48	.89	44	.81	49	.91	60	1.11	79	1.46
Oil-fired new units (2.5% S in oil)	200	59	1.09	51	.94	55	1.02	65	1.20	81	1.50
	500	45	.83	39	.72	40	.74	48	.89	71	1.31
	1000	33	.61	29	.54	30	.56	36	.67	58	1.07
Oil-fired existing unit (2.5% S in oil)	500	55	1.02	46	.85	51	.94	61	1.13	83	1.54
Costs include:		On-site solids disposal of $CaSO_3/CaSO_4$		On-site solids disposal of $CaSO_3/CaSO_4$		Regeneration of SO_2 and conversion to H_2SO_4		Conversion to Na_2SO_4 and regeneration of SO_2/conversion to elemental sulfur		Particulate removal before flue gas enters converter and conversion to H_2SO_4	

Note: [a] Mid 1974 costs plus 25% escalation

[b] Ninety percent SO_2 removal assumed

[c] Based on 5400 hr/yr at rated MW and a net plant heat rate of 10⁴Btu/KWhr (Reference 4-3)

TABLE 4-7. 1975 DIFFERENTIAL OPERATING COSTS[a] FOR UTILITY BOILER FLUE GAS SO_2 REMOVAL

Unit Type	Unit Size (MW)	Lime Slurry Scrubbing[b]		Limestone Slurry Scrubbing[b]		Magnesia Scrubbing[b]		Sodium Carbonate Scrubbing[b]		Catalytic Oxidation[b]	
		10^6\$/yr	Mils/KwHr[c]	10^6\$/yr	Mils/KwHr[c]	10^6\$/yr	Mils/KwHr[c]	10^6\$/yr	Mils/KwHr[c]	10^6\$/yr	Mils/KwHr[c]
Coal-fired new units (3.5% S in coal)	200	3.7	2.6	3.5	2.5	4.3	3.1	5.3	3.8	4.0	2.9
	500	7.1	2.0	6.9	2.0	8.3	2.3	10.3	2.9	8.5	2.4
	1000	11.1	1.6	10.7	1.5	12.9	1.9	16.3	2.3	13.4	1.9
Coal-fired existing units (3.5% S in coal)	200	4.2	3.0	3.5	2.5	4.6	3.2	6.6	4.7	5.5	4.0
	500	8.5	2.5	7.1	2.1	8.6	2.5	13.1	3.7	11.8	3.3
	1000	13.5	1.9	11.5	1.6	13.9	2.0	22.3	3.2	20.5	3.0
Oil-fired new units (2.5% S in oil)	200	3.0	2.1	2.5	1.8	2.9	2.1	3.8	2.8	2.7	1.9
	500	6.1	1.8	5.0	1.4	5.5	1.5	7.4	2.1	5.4	1.5
	1000	9.5	1.3	8.1	1.2	8.7	1.3	12.2	1.8	8.5	1.2
Oil-fired existing unit (2.5% S in oil)	500	7.0	2.0	5.9	1.7	6.6	1.9	9.1	2.6	10.6	3.1

Note: [a] Costs exclude credit for byproducts (See Table 4-5.); includes 15 percent of total capital investment as part of annual indirect costs.

[b] 90 percent SO_2 removal assumed

[c] Based on 5400 Hr/Yr at rated MW and a net plant heat rate of 10^4 Btu/KwHr (Reference 4-3)

that the capital and operating costs for the first three processes mentioned in Section 3.4 are comparable to those given in Tables 4-6 and 4-7:

- Equipment and operating costs for the Shell/UOP process are estimated to be very close to those of the sodium carbonate process.
- Both capital and operating costs for the Chiyoda 101/102 process have been estimated to be quite high (comparable to the highest costs in Tables 4-6 and 4-7).
- Estimates of the capital charges for the Bergbau-Forschung system show them to be in the mid-range of values given in Table 4-6, whereas operating costs for this system are estimated to be very high.

Preliminary cost analyses on some of the catalytic processes have been made by TRW (Reference 4-10); however, those costs seem to be highly optimistic estimates, considering the embryonic stage of development of these processes.

4.2 COMMERCIAL AND INDUSTRIAL BOILERS

Devices in this source sector include all boilers with a capacity greater than 10^6 Btu/hr and up to utility boiler size. These boilers provide process steam for industrial applications (watertube design) and steam and hot water for comfort air heating and cooling in commercial applications (firetube and small watertube).

Cost data for combustion modifications on these types of equipment are virtually nonexistent. Only the most broadly-based estimates are available to the boiler owner and operator at the present time. The most recent information of this kind was published by Bartz, et al., in 1974 (Reference 4-11).

In Reference 4-11, the authors estimated that many boilers presently exceeding EPA New Source Performance Standards (NSPS) could be modified to emit lower nitrogen oxides for about $10,000 per boiler. For boilers with multiple burners this would probably be accomplished by reducing excess air and by staging the combustion process. This latter method, accounting for the largest portion of the total cost, would be implemented by removing from 1/4 to 1/3 of the burners from service. Air flow would be maintained through the out-of-service burners while the fuel flow to the remaining burners would be increased sufficiently to maintain a constant total fuel flow. The burner tips on oil-fired boilers are usually enlarged. Consequently, the active burners would then be supplied with insufficient air to react with all the fuel, leading to the classical off-stoichiometric, or staged, combustion condition.

In the case of boilers with one burner, this modification can be implemented by installing overfire air ports which bypass the burner between the windbox and the boiler. These ports would carry 20 to 30 percent of the total air flow to the furnace volume. Again, the cost of such an installation may be of the order of $10,000 per boiler. As for multiple burner boilers, lowering excess air is assumed to entail negligible capital costs.

If for the $10,000 capital cost estimate the maintenance and operational charges are assumed to be small and the capital cost is annualized at 20 percent, the annual charge will be $2,000. As a result of applying such modifications it is estimated that the emissions from this category of boilers burning only natural gas could be reduced by 50 percent, the emissions from those able to burn both gas and oil could be dropped by 35 percent, and the emissions from those burning oil only could be reduced by 20 percent.

Research and development, including field testing and application of NO_X control methods to this equipment cateogry, is still in its early stages. More accurate cost estimates for these techniques are being developed as part of on-going and planned EPA studies.

4.3 INTERNAL COMBUSTION ENGINES

Cost estimates of NO_X control tecniques for internal combustion engines are presented in this section. Since few of these techniques have actually been implemented in full scale operation, costs are derived first from any actual cost data available and secondly from estimates based on equipment costs, overhaul and maintenance increases, fuel consumption penalties, etc. Reciprocating engines are discussed immediately following and gas turbines conclude the section.

4.3.1 Reciprocating IC Engines

This section will outline costs to control NO_X emissions for control techniques readily available to users of stationary reciprocating engines. As discussed earlier, stationary engines are unregulated for gaseous pollutants and, consequently, little data is available for field-tested controlled engines, particularly for large (> 500 hp) engines. Sufficient data exists, however, to give order of magnitude NO_X control costs for the following engine categories:

- Large (> 100 hp/cyl) natural gas, dual fuel, and diesel fueled engines.
- Small to medium (< 100 hp/cyl) diesel fueled engines
- Gasoline fueled engines (16 - 500 hp)

Costs for large (> 100 hp/cyl) stationary engines, whose emissions and potential reductions are presented in Section 3.1.3.1 can be estimated based on Reference 4-12 and information supplied to Reference 4-13. These costs, however, relate to emission reduction achieved by engines tested in laboratories rather than field installations. Reference 4-12 indicates, nevertheless, that these data are representative.

In contrast to the large stationary engines, more published data exists for smaller (< 500 hp) gasoline and diesel engines which must meet State (California) and Federal emission limits for mobile applications. Stationary engines in this size range are versions of these mobile engines. Therefore, costs can be estimated based on a technology transfer from mobile applications to stationary service, keeping in mind that in some cases mobile duty cycles (variable load) can differ from stationary duty cycles (rated load) and, hence, costs (e.g., fuel penalties) associated with a control technique used in a stationary application may vary from the mobile case.

Control costs for the three categories discussed above may include:

- Initial cost increases for control hardware and/or equipment associated with a particular control (e.g., larger radiatior for manifold air cooling or more engines as a result of derating)
- Operating cost increases which are either increased fuel consumption and/or increased maintenance associated with NO_x control system, and
- Combinations of initial and operating cost increases

4.3.1.1 Control Costs for Large (> 100 hp/cyl) Bore Engines

Table 4-8 lists differential cost considerations for control techniques available to users of large stationary engines. Cost differentials presented in Table 4-8 may be related to actual installations using baseline data presented in Table 4-9. In practice, these figures vary depending on the application, but, in general, these figures are representative of the majority of applications. Basically, these controls involve an operating adjustment with the exception of derating and manifold air cooling which would require hardware additions. Derating is not a viable technique for existing installations unless additional units may be added to satisfy total power requirements. These techniques are summarized as follows:

Control	Cost Impact
retard	increased fuel consumption
air-to-fuel changes	increased fuel consumption
derate	fuel penalty, additional hardware, and increased maintenance associated with additional units
manifold air cooling	increased cost to enlarge cooling system, and increased maintenance for cooling tower water treatment
combinations of above control techniques	initial, fuel, and maintenance increases as appropriate

The impact of the above control costs may vary considerably given the following considerations:

- Standby (< 200 hr/yr) application control costs are primarily a result of initial cost increases due to an emission control, whereas continuous service (> 6000 hr/yr) control costs are largely a function of fuel consumption penalties.

TABLE 4-8. DIFFERENTIAL COSTS FOR NO_x CONTROL TECHNIQUES FOR LARGE BORE ENGINES

Control	Initial	Fuel	Maintenance	Comments
Retard	—	~bsfc increase	—	Maintenance may be required for early replacement of valves.
Air-to-fuel	—	~bsfc increase	—	
Derate	Increase by bmep (uncontrolled)/ bmep (controlled)	~bsfc increase	Increase by ratio of bmep	Increased initial + maintenance for additional units to supply total hp requirement.
Cooled inlet manifold air temperature	Increase 1-2 percent of basic price	—	~20 percent	Increased maintenance for cooling tower water treatment.

TABLE 4-9. TYPICAL BASELINE COSTS FOR LARGE (>100 HP/CYL) ENGINES[a]

Costs	Gas	Dual Fuel	Diesel
1. Initial,[b] $/hp	130	130	130
2. Maintenance, $/hp-hr	0.003	0.003	0.003
3. Fuel and lube, $/hp-hr	0.008	0.0077	0.0173
Total Operating, 2 + 3	0.011	0.0107	0.0203

[a] Based on Reference (4-12) and information supplied to Reference (4-13) by manufacturers.

[b] Includes basic engine and cooling system.

[c] Reference 4-13.

- Controls which require additional hardware with no associated fuel penalty (e.g., manifold air-cooling) may be more cost effective in continuous service (> 6000) hr/yr) than operating adjustments which impose a fuel penalty (e.g., retard, or air-to-fuel change).
- The price of fuel can affect the impact of a control which incurs a fuel penalty. For example, a control which imposes a fuel penalty of 5 percent for both gas and diesel engines has more impact on the diesel fueled engine because diesel oil costs \$2.20/10^6 Btu compared to \$1.00/10^6 for natural gas. This impact may diminish if gas prices increase or gas prices increase more rapidly than oil prices (either is likely).

4.3.1.2 Control Costs for Small and Medium Gasoline and Diesel Fueled Engines

Control costs for these engines can be characterized by those incurred to meet State and Federal emission limits for automotive vehicles. Again, these costs consist of initial purchase price increases for control hardware and increased operating costs (fuel and maintenance cost increases).

Table 4-10 lists typical costs for techniques implemented for 1975 diesel fueled truck engines. These costs are presented to indicate order of magnitude effects. More research is required to relate specific emission control reductions to initial and operating cost increases for stationary engine applications.

Table 4-11 gives control hardware costs to meet gasoline-fueled passenger vehicle emission limits through 1976. Note that cost increases correspond to increasingly more complex controls to meet more stringent emission limits.

Figure 4-3 illustrates the effect of various control techniques on fuel economy. Fuel cost increases can be easily derived from typical gasoline costs, presently \$0.45 - 0.55/gallon. In addition to this operating expense, control techniques utilizing catalysts and EGR require periodic maintenance.

Manufacturers, in addition, incur certification costs for gasoline and diesel fueled engines which must meet State and Federal regulations. These costs are passed on to the user in the form of increased initial costs. Manufacturers of diesel fueled engines report these costs range from \$50,000 to \$100,000 for a particular engine family. This can result in a \$125 cost per engine based on a low sales volume family[1].

4.3.2 Gas Turbines

This section discusses the economic considerations for reducing NO_X emissions from stationary gas turbines by way of combustion modification. Cost considerations for exhaust

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[1] Based on information supplied by manufacturers to Reference 4-13.

TABLE 4-10. TYPICAL CONTROL COSTS FOR DIESEL FUELED ENGINES USED IN HEAVY DUTY (>6000 LB) Vehicles[a]

Initial

baseline	engine	\$30-50/hp
	cooling system	8-14% engine
turbocharger		\$3/hp
aftercooler		6-10% engine
EGR		\$2-3/hp

Operating

Fuel:	Fuel penalties range from 3 to 8 percent for various techniques. Typical present fuel cost: \$0.35/gallon #2 diesel or \$1.75 – 2.25/10^6 Btu
Maintenance:	EGR system will require periodic cleaning. Note that turbocharged, aftercooled engines require additional maintenance for the turbocharger and aftercooler compared to a similarly rated naturally aspirated version.

[a] Based on information supplied to Reference 4-13 by manufacturers.

TABLE 4-11. ESTIMATES OF STICKER PRICES FOR EMISSIONS HARDWARE FROM 1966 UNCONTROLLED VEHICLES TO 1976 DUAL-CATALYST SYSTEMS (REFERENCE 4-14).

Model Year	Configuration	Typical Hardware			
		Value Added	List Price	Excise Tax	Sticker Price
1966	PCV-Crank Case	1,90	2,85	0,15	3,00
1968	Fuel Evaporation System	9,07	14,25	0,75	15,00
1970	Carburetor Air/Fuel Ratio	0,61	0,95	0,05	1,00
	Compression Ratio	1,24	1,90	0,10	2,00
	Ignition Timing	0,61	0,95	0,05	1,00
	Transmission Control System	2,49	3,80	0,20	4,00
	Total 1970				8,00
1971-1972	Anti-Dieseling Solenoid	3,07	4,75	0,25	5,00
	Thermo Air Valve	2,49	3,80	0,20	4,00
	Choke Heat By-Pass	2,74	4,18	0,22	4,40
	Assembly Line Tests, Calif (1/10 vol)	0,18	0,57	0,03	0,60
	Total 1971-72				14,00
1973	OSAC (Spark Advance Control)	0,48	0,95	0,05	1,00
	Transmission Changes (some models)	0,63	0,95	0,05	1,00
	Induction Hardened Valve Seats (4 and 6 cyl)	0,72	1,90	0,10	2,00
	EGR (11 – 14%) Exhaust Recirculation	5,48	9,50	0,50	10,00
	Air Pump – Air Injection System	27,16	43,32	2,28	45,60
	Quality Audit, Assembly Line (1/10 vol)	0,23	0,38	0,02	0,40
	Total 1973				60,00

TABLE 4-11. (Continued)

Model Year	Configuration	Typical Hardware			
		Value Added	List Price	Excise Tax	Sticker Price
1974	Induction Hardened Valve Seat V-8	0.72	1.90	0.10	2.00
	Some Proportional EGR (1/10 vol at $52)	3.21	4.94	0.26	5.20
	Precision Cams, Bores, and Pistons	2.44	3.80	0.20	4.00
	Pretest Engines – Emissions	1.80	2.85	0.15	3.00
	Calif. Catalytic Converter System (1/10 vol at $64)	4.02	6.08	0.32	6.40
	Total 1974				20.60
1975	Proportional EGR (acceleration-deceleration)	20.07	30.02	1.58	31.60
	New Design Carburetor with Altitude Compensation	7.52	14.25	0.75	15.00
	Hot Spot Intake Manifold	2.87	4.75	0.25	5.00
	Electric Choke (element)	2.67	4.75	0.25	5.00
	Electronic Distributor (pointless)	4.35	9.50	0.50	10.00
	New Timing Control	1.40	2.85	0.15	3.00
	Catalytic – Oxidizing-Converter	18.86	34.20	1.80	36.00
	Pellet Charge (6 lb at $2/lb)	12.00	20.52	1.08	21.60
	Cooling System Changes	1.17	1.90	0.10	2.00
	Underhood Temperature Materials	0.63	0.95	0.05	1.00
	Body Revisions Welding Presses	0.67	1.90	0.10	2.00
	Assembly Line Changes	0.13	0.95	0.05	1.00
	End of Line Test Go/No-Go	1.85	2.85	0.15	3.00
	Quality Emission Test	1.22	1.90	0.10	2.00
	Total 1975				118.20
1976	2 NO_x Catalytic Converters[a]	22.00	37.05	1.95	39.00
	Electronic Control[a]	28.00	47.50	2.50	50.00
	Sensors[a]	3.00	5.70	0.30	6.00
	Total 1976				134.00

[a] 1976 most common configuration

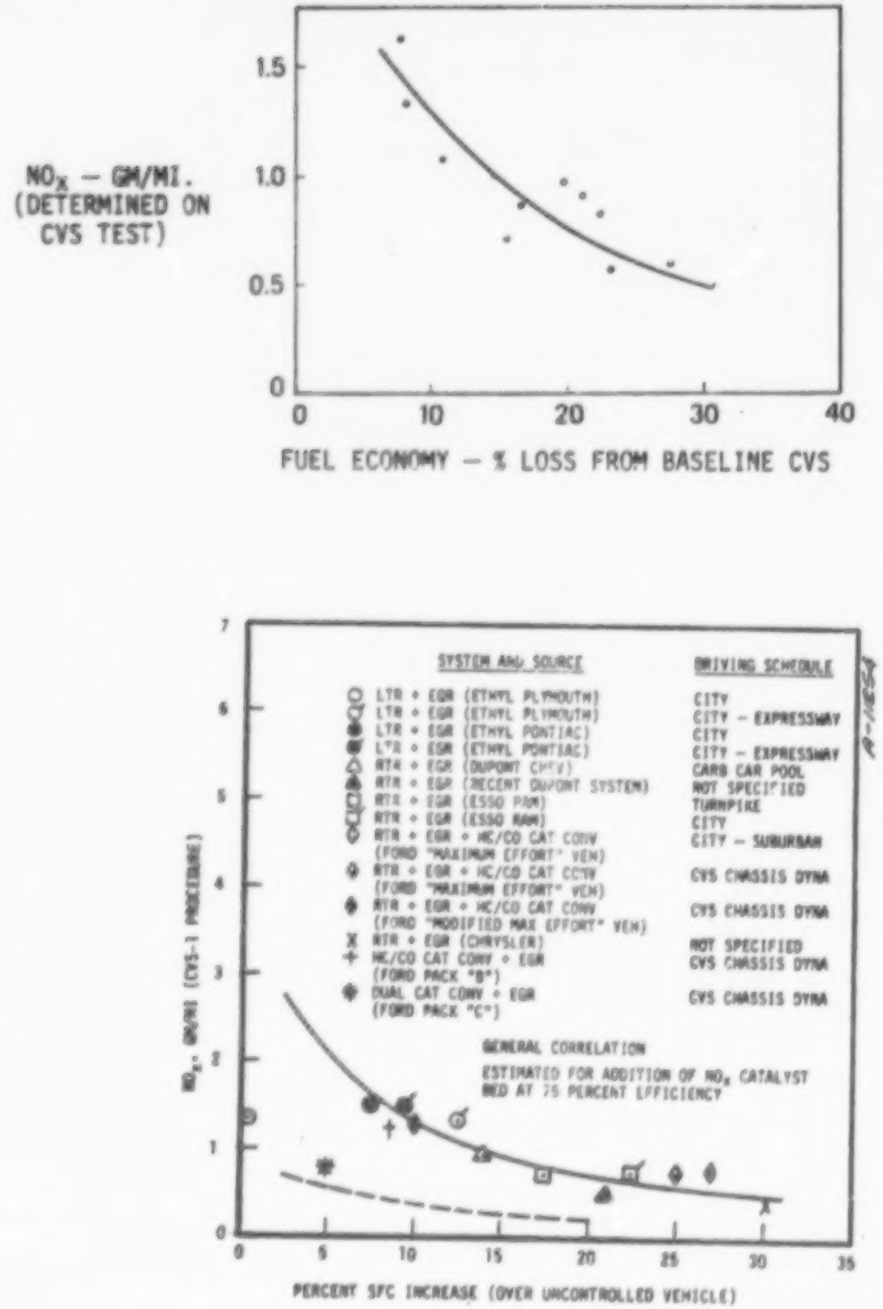

Figure 4-3.* Effect of NO_x emissions level on fuel penalty. (Reference 4-15)

gas cleanup are not presented since that technique is not considered a viable means of NO_x reduction for stationary units.

The most recent cost studies on NO_x controls for gas turbines have been performed by Aerospace (Reference 4-14) and EPA (Reference 4-16). In the absense of any nationwide limitation on NO_x emission levels, very little data exist relative to actual costs. The smaller capacity gas turbines, as was previously cited, may very well be capable of NO_x levels below proposed standards without the installation of wet controls, whereas the larger units almost universally will require either water or steam injection and possibly some minor combustor modifications.

As input to the Aerospace study, San Diego Gas and Electric provided their investment costs for water injection retrofit to three units as presented in Table 4-12. These costs are based on a baseline investment cost of an uncontrolled simple cycle turbine of about \$80 - 100/Kw and an operational cost of 20 - 24 mils/kw hour for intermediate loads (6000 hours per year; fuel costs of 80¢/10^6Btu). In this example, the incremental investment costs for water injection can be as high as 10% for the 20 MW plant and as low as 6% for the 49 and 81 MW plants. Investment and operating costs for steam injection are generally accepted to be higher than water injection unless superheated steam is available on-site. A comparison of investment and operating costs for both water and steam injection as a function of turbine size is presented in Table 4-13. Wet control costs are seen to be prohibitive for the turbines of smaller size but, in general, wet controls will not be required by these units to effectively reduce emission levels below proposed standards. Noting that operating costs decrease as a function of both turbine size and load factor, it is conceivable that the base loading with a 65 MW unit operational cost could be as low as 2.5%.

A more extensive breakdown of the costs for wet and dry controls has been assembled by EPA in support of proposed emission standards. Table 4-14 presents the cost of NO_X control for small gas turbines. The table illustrates the cost of dry controls for two units, a 350 hp and a 3500 hp unit, and the cost of wet controls for the 3500 hp turbine. Although it is assumed that most of the smaller capacity units will be sufficiently controlled by dry control to exclude the use of wet controls, it is not certain that the larger capacity small turbines (50 M Btu) will not require water or steam injection; therefore, estimates are included for both methods of control. Operating costs vary from 17% for the standby 350 hp turbine to a low of 1.3% for the 8000 hr/year 3500 hp dry controlled unit. Table 4-15 presents similar cost estimates for large gas turbines equipped with water injection. Again these are costs provided by San Diego Gas & Electric to EPA. Costs here do not include on - site personnel since controls were designed to operate automatically on the generally unattended turbine.

TABLE 4-12. WATER INJECTION INVESTMENT COST (SAN DIEGO GAS AND ELECTRIC)

Control System	Gas Turbine Size		
	20 MW	49 MW	81 MW
Combustor modifications including water injection nozzles	$1.00/kw	$0.86/kw	$1.04/kw
Water injection pumps and water regulation system	$3.54/kw	$2.88/kw	$3.10/kw
Associated piping and water storage facilities	$1.72/kw	$1.05/kw	$0.87/kw
Water treatment equipment	$0.90/kw	$0.47/kw	$0.47/kw
General expenses including engineering, administration, testing taxes	$1.15/kw	$0.82/kw	$0.57/kw
TOTAL	$8.31/kw	$6.07/kw	$6.05/kw

TABLE 4-13. WATER/STEAM INJECTION COST AS A FUNCTION OF POWER PLANT SIZE

MW Output	Investment Cost, Percent Baseline		*Operational Cost, Percent Baseline	
	Water	Steam	Water	Steam
0.26 (350 hp)	100.0	150.0	55.0	165
2.90 (3900 hp)	18.0	24.0	6.5	32
20.00	10.0	12.0	6.0	–
33.00	7.3	10.6	5.7	–
65.00	7.3	10.6	5.7	–

*For peaking gas turbine, 1000 hour/year

TABLE 4-14. 1974 ESTIMATED COSTS OF NO_x CONTROLS FOR SMALL GAS TURBINES (REFERENCE 4-16)

Size, hp	350		3,500		3,500	
Purchase cost (PC), uncontrolled	8,800		110,000		110,000	
Total installed cost (TIC), 1.3xPC	11,400		143,000		143,000	
Total capital investment (TCI), 1.25XTIC	14,300		178,800		178,800	
Control increment, percent	Dry 20		Dry 12		Wet 25	
TCI, controlled	17,200		200,000		224,000	
Unit investment, controlled, $/hp	49		57		64	
Heat rate, Btu/hph	12,000		11,000		11,000	
Equivalent hours duty per year	100[a]	8,000[b]	100	8,000	100	8,000
Fuel @ $0.91/MBtu[c]	380	30,600	3,500	280,300	3,500	280,300
Fixed charges, uncontrolled[d]	2,600	2,600	32,200	32,200	32,200	32,200
Total annual cost, uncontrolled	3,000	33,200	35,700	312,500	35,700	312,500
Utilities[e]	--	--	--	--	12	1,000
Incremental fixed charges[d]	520	520	3,900	3,900	8,000	8,000
Total annual cost, controlled	3,500	33,700	39,600	316,400	43,700	321,500
Control cost, percent	17	1.6	11	1.3	22	2.9

Notes:

[a] As in emergency service, including readiness tests

[b] As in pipeline service

[c] In the pipeline application, fuel from the line would be much less expensive

[d] Carrying charges 17 percent, maintenance 1 percent

[e] Raw water, regeneration chemicals, and power together assumed $1/1000 gallon

TABLE 4-15. 1974 ESTIMATED COSTS OF WET NO_x CONTROLS FOR LARGE GAS TURBINES (REFERENCE 4-16)

Size, MW	25			4x65		
Capital costs in thousands of dollars:						
Total capital investment (TCI)[a], uncontrolled		2800			26000	
Equivalent hours duty per year	8000	1000	1000	4000	1000	1000
Water/fuel ratio	0.5	0.5	0.8	0.5	0.5	0.8
Control increment,[b] percent	10.0	8.5	9.5	3.9	3.5	3.9
TCI, controlled	3120	3040	3070	27000	26900	27000
Unit investment, controlled, $/kw	125	121	123	104	103	104
Annualized costs in thousands of dollars:						
Heat rate, Btu/kwh		12400			11700	
Fuel @ $0.91/MBtu	2260	282	282	11070	2770	2770
Fixed charges, uncontrolled[d]	504	504	504	4670	4670	4670
Total annual cost, uncontrolled	2764	786	786	15740	7440	7440
Utilities[e]	9	1	2	40	10	16
Incremental fixed charges	57	43	49	180	160	180
Total annual cost, controlled	2830	830	837	15960	7610	7640
Incremental annual cost, percent	2.3	5.6	6.5	1.4	2.3	2.6

Notes: [a] Applying to the 25 MW case, the 1970 Federal Power Survey datum of $85/kw, escalating from 1968 to 1974 at 5 percent compounded, and assuming a weak economy of scale for the larger case.

[b] Wet controls include an injection system sized for peak injection rate.

[c] In the 8000-hour case representing a pipeline compressor, fuel from the line would be much less expensive.

[d] Carrying charges 17 percent, maintenance 1 percent.

[e] Raw water, regeneration chemicals, power and sewerage together at $1/1000 gallons.

A cost effectiveness summary is presented in Table 4-16 and illustrates the relationship between control costs and resultant NO_x levels. Note that using the given reduction assumptions, the 3500 hp unit with dry controls only would not meet the present San Diego County standards of 42 and 75 ppm NO_x @15 percent oxygen for gas and liquid fuels, respectively.

In summary, the primary economic considerations in controlling NO_x from gas turbines are:

- Wet controls are by far the most expensive means of NO_x control, but they are presently the only adequate means for the large units (> 50M Btu).
- Dry controls are the most desirable in terms of cost but alone are applicable only to the smaller units (< 50M Btu). These controls may not be sufficient for those units approaching 50M Btu in size.
- Incremental operating costs decrease as loading factor and size increase. Increments as low as 1.3% are shown.

4.4 COMMERCIAL AND RESIDENTIAL HEATING

This section discusses the economic considerations in reducing bulk emissions from both commercial and residential space heating units for the three presently applicable strategies presented in Section 3.1.4:

- Tuning
- Burner replacement
- Unit replacement

A scan of several service organizations across the country indicates that the tuning procedure consists of cleaning, leak detection, sealing, and flame adjustment using the "eyeball" technique. None of the service companies contacted offered the instrumented tuning described in Section 3.1.4, but some were aware of this method and believed it would be available in the near future at a substantially higher cost than the present service. The presently available tuning procedure costs a minimum of $45 for the average residential unit while cost increases with unit size, necessary replacement parts, and abnormal time requirements.

Burner replacement in residential units is considered an uncommon practice by servicemen since new burner costs, installation labor cost and furnace life expectation on the order of 10 to 15 years make burner replacement very costly. New burners cost a minimum of $35, and when added to total installation costs (labor and adjustment) at approximately $20 per hour for two hours minimum, the burner replacement costs at least $75. Burner replacement in some cases may not be effective in reducing emissions and, in fact, could possible increase pollutant production if furnace-burner compatibility is not determined prior to installation. This amount would not seem to be cost effective for residential units, but the emergence of

TABLE 4-16. COST-EFFECTIVENESS SUMMARY (REFERENCE 4-16)

Scale	Fuel	NO_X Concentration, ppmv			Method	Incremental Unit Cost
		Uncontrolled		Controlled[a]		
350 hp	Gas	60		42	Dry	1.6% in pumping service
	Oil	90		68	Dry	
3500 hp	Gas	70		49	Dry	1.3% in pumping service
	Oil	110		83	Dry	
3500 hp	Oil	110		37[b]	Wet	2.9% in pumping service
			W/F = 0.5	0.8		W/F = 0.5
25 MW	Gas	160	54	36	Wet	5.6% to 6.5% in peaking service
	Oil	220	74	50	Wet	
4x65 MW	Gas	200	67	45	Wet	2.3% to 2.6% in peaking service
	Oil	260	88	59	Wet	

Notes:

[a] Assuming 25 percent reduction for oil, 30 percent for gas, with dry controls.
Assuming 25 percent, attributable to the dry controls incorporated with wet controls, compounded by further reductions of 55 percent at W/F = 0.5, 70 percent at W/F = 0.8.

[b] At W/F = 0.5

new low emission burners and the promulgation of NO_x emission restrictions could make this the most attractive control alternative. Commercial burner replacement is a more common practice owing to the characteristically higher unit costs and the longer life expectancies.

Unit replacement strictly for emission control is not cost effective; however, estimates for replacement are included for units in poor condition or units in need of extensive repair. Table 4-17 provides estimates for residential and commercial unit replacement costs.

4.5 ADDITIONAL COST DATA REQUIREMENTS

While this report has attempted to present general cost estimates of NO_x control techniques for the primary stationary source equipment categories, there exists a further requirement for the collection of a substantially more extensive data base from which estimates can be made. The utility boiler category comprises the bulk of published cost information since this equipment type bore the initial thrust of NO_x control technology. Only recently have the remaining equipment categories been subject to pilot or full scale testing, and therefore extensive cost data is not yet available. This section indicates the equipment categories and which equipment types therein require further generation of economic data for future NO_x control cost estimates. An important point to remember is that all published economic data no matter how extensively presented, will only provide general guidelines to those decision makers considering the implementation of the various control techniques. Actual costs must be determined on a unit-by-unit basis.

4.5.1 Utility Boilers

A relatively large quantity of data on the economics of NO_x control technology presently exists for utility boilers. However, this information is generally diffuse in nature since it is derived from many sources. In addition, much of the potentially valuable cost figures are proprietary, residing with individual electric utility companies. Further insight into the cost-effectiveness of modifying a utility boiler combustion process will be gained by satisfying the following requirements:

- Compilation of more complete information on the costs of installing a flue gas recirculation system on "typical" existing units for all three conventional fuels.
- Acquisition of additional data on the installed equipment costs of off-stoichiometric combustion techniques.
- Acquisition of information on all aspects of differential operating costs associated with each control technique.
- Preparation of "case studies" of individual utility companies that have used combustion modification techniques in order to give a profile of user experiences.

TABLE 4-17. TYPICAL COSTS OF GAS FIRED SPACE HEATING UNITS (REFERENCE 4-17)

Capacity	Floor Furnaces	Forced Air*	Space Heaters
35,000 Btu	225-245	-	380 suspended
65,000	270-290	395-450	450 suspended
100,000	-	460-530	925 floor
300,000	-	670-780	2400 floor
750,000	-	-	5150 floor

*Add 15% for oil or coal firing.

4.5.2 Industrial Boilers

As for most of the other equipment types, there is a general lack of cost data associated with combustion modification techniques implemented on industrial-size boilers. It is anticipated that this data base will be augmented by ongoing EPA-sponsored boiler field tests. At this time, however, the information gaps are large. In order to present a more complete picture of the feasibility of combustion modification techniques to the boiler operator and/or owner, the following cost data must be generated:

- For multiburner boilers, the installed equipment costs of off-stoichiometric combustion techniques and the applicability and installed equipment costs of a flue gas recirculation system
- The installed equipment costs of low excess air firing on all boiler types
- Differential operating costs (e.g., increased fuel consumption) of all techniques implemented on all applicable boiler types

4.5.3 Internal Combustion Engines

This equipment sector consists of both reciprocating IC engines and gas turbines. In contrast to reciprocating engines which have such a diversity of equipment combinations, gas turbine equipment combinations are relatively uncomplicated. In view of this difference, reciprocating engine economics are generally presented in terms of engine capacity and/or fuel where gas turbines are discussed by equipment type and/or capacity.

4.5.3.1 Reciprocating Engines

Further cost analyses for reciprocating IC engines are recommended in the following capacity/fuel combinations:

- DEMA (> 100 hp/cyl)
  - present cost estimates derive from the manufacturers experimental in-house units; future data must be compiled from field units particularly regarding cost and control tradeoff in the retrofit unit
  - Cost data must be generated first for specific controls and then for various control combinations and their relationship to control effectiveness
- Mid-Power Engines — almost no cost data for stationary units in this capacity range exists at the present time
  - the bulk of the cost information deals with diesel fueled truck applications however the contrasting load cycles and less restrictive packaging requirements of stationary installations do not lend to accurate cost data transfer. Data must be generated from stationary units.

  - gas fueled units require the entire cost analyses spectrum as essentially no data exist for stationary installations.
  - individual and combinations of control cost data versus control effectiveness must be determined for all equipment categories.
- Small Gasoline Engines — here again, little data exist for stationary application and cost transfer from mobile units is not effective. Essentially all economic aspects of control costs must be investigated in this capacity/fuel range.

4.5.3.2 Gas Turbines

Gas turbine cost data, although more complete than those of reciprocating engines, is lacking in the following areas:

- Utility Applications
  - specific cost data exist on wet control techniques from an actual on-site application but typical costs cannot be assumed from one installation. As wet controls come into more common usage, detailed cost analyses must be undertaken..
  - No on-site cost data exist for dry controls in utility turbines.
- Equipment Classifications
  - open cycle turbines encompass the majority of any existing economic data. Further information is required for on-site wet controls and a complete cost analysis is needed for dry controls as they emerge.
  - Regenerative cycle turbines again require economic data covering the entire range of applicable controls.
  - Combined cycle installations are just recently gaining in popularity and consequently cost information is scarce.
  - As wet and dry controls become more common, control cost-control effectiveness relationships must be determined for all classes of equipment.

4.5.4 Space Heating

The space heating sector cost data base for NO_x control techniques suffers from lack of control implementation in the commercial heating segment and absence of viable NO_x control techniques in the residential segment.

- Commercial Space Heating
  - some cost information from industrial boilers may be applicable on the upper capacity range but contrasting duty cycles introduce uncertainty in the cost data transfer.

  - detailed economic analyses are recommended for all aspects of commercial space heating NO_x control.

- Residential Space Heating — the present control strategy within the sector is the overall reduction of unit emissions since compatible NO_x controls remain to be developed. Cost analyses must be performed for the present strategies until specific NO_x controls emerge.

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4-11 Bartz, D. R., et al., "Control of Oxides of Nitrogen from Stationary Sources in the South Coast Air Basin," prepared for the California Air Resources Board, September, 1974.

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4-13 Acurex Corporation, Preparation of a Standards Support Document for New Stationary Reciprocating Internal Combustion Engines, EPA Contract No. 68-02-1318, Task No. 7.

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4-15 Calspan Corporation, "Technical Evaluation of Emission Control Approaches and Economics of Emission Reduction Requirements for Vehicles Between 6000 and 14000 Pounds GVW," EPA-460/3-73-005, November 1973.

4-16 Durkee, K., E. A. Noble, F. Collins and D. Marsland, "Draft of Standards Support Document for an Investigation of the Best System of Emission Reduction for Stationary Gas Turbines," Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina, August 1974.

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APPENDIX A

A numerical ranking by NO_x production is presented for the 137 equipment/fuel combinations as discussed in Section 2.1. Estimates are believed to be fairly accurate for the top 30 or so sources which comprise greater than 80 percent of the total emissions. The proportionate error undoubtedly increases whicle progressing to the minor sources so that the numerical ranking of the very minor sources is qualitative at best.

The sources at the end of the list were not given numerical rankings because they are regarded as negligible, or emission data was not available. Mixed fuel firing is included in the not available category even though its use is prevalent. This is because fuel consumption data is reported in terms of constituent fuel only without regard to whether it is fired singly or mixed with another fuel. A number of other equipment/fuel types could be listed in the negligible category.

It is emphasized that a high source placement in the emission rankings does not necessarily mean that individual units are high emitters. Rather, the sources may have relatively low emission factors, but a high placement due to the large number of installed units of that type. Such is the case, for example, for tangential coal fired utility boilers. These units are of a fairly standard design and were not subdivided into design types, as was necessary for wall fired utility boilers. It is also emphasized that sources on this list are confined to controllable types of processes and exclude such things as forest fires and open burning.

Rankings are presented in the following Table A-1.

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
1.	IC Engines, Spark Ignition, Gas Fired	1.873	16.06	
2.	Utility Boiler, Tangential Firing, Bituminous Coal	1.388	11.90	27.96
3.	Utility Boiler, Cyclone Firing, Bituminous Coal	0.730	6.26	34.22
4.	Utility Boiler, Horizontally Opposed Wall Firing, Gas	0.568	4.87	39.09
5.	Utility Boiler, Horizontally Opposed Wall Firing, Dry Bottom, Bituminous Coal	0.412	3.53	42.62
6.	Utility Boiler, Front Wall Firing, Dry Bottom, Bituminous Coal	0.412	3.53	46.15
7.	Utility Boiler, Front Wall Firing, Gas	0.393	3.37	49.52
8.	IC Engine, Diesel, Oil and Dual Fuels	0.316	2.71	52.23
9.	Utility Boiler, Horizontally Opposed Wall Firing, Wet Bottom Bituminous Coal	0.306	2.62	54.85
10.	Utility Boiler, Front Wall Firing, Wet Bottom, Bituminous Coal	0.302	2.59	57.44
11.	Utility Boiler, Horizontally Opposed Wall Firing, Residual Oil	0.271	2.32	59.76
12.	Utility Boiler, Front Wall Firing, Residual Oil	0.271	2.32	62.08
13.	Industrial Boiler, Bent Tube Wall Fired Packaged Watertube, Residual Oil	0.2064	1.77	63.85
14.	Industrial Boiler, Firetube Wall Fired Packaged Scotch, Residual Oil	0.1924	1.65	65.50
15.	Utility Boiler, Tangential Firing, Residual Oil	0.177	1.52	67.02
16.	Gas Turbines, Gas Fired	0.172	1.47	68.49
17.	Industrial Boiler, Front Wall Firing Field Erected Watertube, Residual Oil	0.165	1.41	69.90
18.	Industrial Boiler, Horizontally Opposed Wall Firing Field Erected Watertube, Residual Oil	0.165	1.41	71.31
19.	Utility Boiler, Tangential Firing, Gas	0.153	1.31	72.62
20.	Industrial Boiler, Bent Tube Wall Fired Packaged Watertube, Gas	0.139	1.19	73.81
21.	Industrial Boiler, Stoker, Spreader Field Erected Watertube, Coal	0.136	1.17	74.98
22.	Utility Boiler, Vertical Firing, Bituminous Coal	0.127	1.09	76.07
23.	Gas Turbine, Oil Fired	0.119	1.02	77.09

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
24.	Nitric Acid Production	0.11	0.94	78.03
25.	Process Heating, Glass Manufacture	0.11	0.94	78.97
26.	Residential Heating, Hot Air Furnace, Distillate Oil	0.107	0.92	78.89
27.	Residential Heating, Hot Air Furnace, Gas	0.106	0.91	80.80
28.	Industrial Boiler, Tangential Firing, Field Erected Watertube, Residual Oil	0.106	0.91	81.71
29.	Petroleum Catalytic Crackers (FCC)	0.099	0.85	82.56
30.	Residential Heating, Steam or Hot Water, Distillate Oil	0.097	0.83	83.39
31.	Industrial Boiler, Horizontally Opposed Wall Firing Field Erected Watertube, Gas	0.087	0.75	84.14
32.	Industrial Boiler, Bent Tube Wall Fired Field Erected Watertube, Residual Oil	0.086	0.74	84.88
33.	Industrial Boiler, Stoker, Underfeed, Field Erected Watertube, Coal	0.077	0.66	85.54
34.	Industrial Boiler, Firetube Wall Fired Packaged Fire Box, Residual Oil	0.076	0.65	86.19
35.	Industrial Boiler, Stoker, Underfeed, Packaged Watertube, Coal	0.067	0.57	86.76
36.	Industrial Boiler, Front Wall Firing, Field Erected Watertube, Gas	0.059	0.51	87.27
37.	Process Heating, Cement Kilns, Coal Fired	0.055	0.475	87.75
38.	Process Heating, Cement Kilns, Gas Fired	0.047	0.40	88.15
39.	Commercial Boiler, Firetube Wall Fired Packaged Scotch, Residual Oil	0.0452	0.39	88.54
40.	Commercial Boiler, Firetube Wall Fired Packaged Firebox, Residual Oil	0.0452	0.39	88.93
41.	Industrial Boiler, Bent Tube Wall Fired Field Erected Watertube, Gas	0.045	0.39	89.32
42.	Industrial Boiler, Firetube Wall Fired Packaged Scotch, Gas	0.044	0.38	89.70
43.	Industrial Boiler, Stoker Spreader Packaged Watertube, Coal	0.043	0.37	90.07
44.	Residential Heating, Steam or Hot Water, Gas	0.040	0.34	90.41

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
45. Industrial Boiler, Firetube Wall Fired Packaged HRT, Residual Oil	0.040	0.34	90.75
46. Industrial Boiler, Firetube Wall Fired Packaged Firebox, Gas	0.038	0.33	91.07
47. Utility Boiler, Stoker, Spreader, Coal	0.037	0.32	91.40
48. Industrial Boiler, Stoker, Overfeed, Field Erected Watertube, Coal	0.037	0.32	91.72
49. Commercial Boiler, Firetube Wall Fired Packaged Scotch, Gas	0.036	0.31	92.03
50. Commercial Boiler, Firetube Wall Fired Packaged Firebox, Gas	0.036	0.31	92.34
51. Industrial Boiler, Tangential Firing Field Erected Watertube Gas	0.032	0.27	92.61
52. Industrial Boiler, Tangential Firing Field Erected Watertube, Coal	0.030	0.26	92.87
53. Residential Heating, Room Heater With Flue, Gas	0.028	0.24	93.11
54. Explosive Manufacture	0.028	0.24	93.35
55. Industrial Boiler, Cyclone Field Erected Watertube, Coal	0.028	0.24	93.59
56. Residential Heating, Floor, Wall or Pipeless Heaters, Gas	0.027	0.23	93.82
57. Iron and Steel Industry, Open Hearth Furnace	0.025	0.21	94.03
58. Iron and Steel Industry, Sintering	0.024	0.21	94.24
59. Residential Heating, Room Heater With Flue, Distillate Oil	0.024	0.21	94.45
60. Incineration, Industrial	0.023	0.20	94.65
61. Commercial Boiler, Firetube, Wall Fired Cast Iron, Residual Oil	0.0226	0.19	94.84
62. Commercial Boiler, Firetube Wall Fired HRT, Residual Oil	0.0226	0.19	95.03
63. Industrial Boiler, Firetube Wall Fired Packaged HRT, Gas	0.020	0.17	95.20
64. Utility Boiler, Cyclone, Residual Oil	0.019	0.16	95.36
65. Commercial Boiler, Firetube Wall Fired Packaged Scotch, Distillate Oil	0.0184	0.16	95.52

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
66.	Commercial Boiler, Firetube Wall Fired Firebox, Distillate Oil	0.0184	0.16	95.68
67.	Industrial Boiler, Stoker General, Field Erected Watertube, Coal	0.018	0.15	95.83
68.	Commercial Boiler, Firetube Wall Fired HRT, Gas	0.018	0.15	95.98
69.	Incineration, Municipal	0.018	0.15	96.13
70.	Commercial Boiler, Wall Fired Cast Iron, Gas	0.018	0.15	96.28
71.	Commercial Boiler, Firetube, Stoker, Miscellaneous, Firebox, Coal	0.018	0.15	96.43
72.	Process Heating, Cement Kilns, Oil	0.0165	0.14	96.57
73.	Utility Boiler, Stoker Underfeed, Coal	0.016	0.14	96.71
74.	Residential Heating, Floor, Wall or Pipeless Heater, Distillate Oil	0.016	0.14	96.85
75.	Industrial Boiler, Stoker, Overfeed, Packaged Watertube, Coal	0.016	0.14	96.99
76.	Industrial Boiler, Firetube Wall Fired Packaged Scotch, Distillate Oil	0.0156	0.13	97.12
77.	Industrial Boiler, Wall Fired Packaged Watertube, Distillate Oil	0.0156	0.13	97.25
78.	Utility Boiler, Tangential Firing, Lignite Coal	0.014	0.12	97.37
79.	Industrial Boiler, Cyclone Field Erected Watertube, Residual Oil	0.014	0.12	97.49
80.	Sulfuric Acid Production	0.011	0.094	97.58
81.	Utility Boiler, Horizontally Opposed Wall Firing, Distillate Oil	0.011	0.094	97.67
82.	Utility Boiler, Front Wall Firing, Distillate Oil	0.011	0.094	97.76
83.	Residential Heating, Room Heater Without Flue, Gas	0.011	0.094	97.86
84.	Residential Heating, Room Heater Without Flue, Distillate Oil	0.010	0.086	97.95
85.	Utility Boiler, Vertical Firing, Anthracite Coal	0.010	0.086	98.03
86.	Industrial Boiler, Firetube Stoker Underfeed Packaged Firebox, Coal	0.010	0.086	98.12
87.	Commercial Boiler, Firetube, Wall Fired HRT, Distillate Oil	0.0092	0.079	98.20

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
88. Commercial Boiler, Wall Fired Cast Iron, Distillate Oil	0.0092	0.079	98.28
89. Utility Boiler, Cyclone, Lignite Coal	0.009	0.077	98.35
90. Industrial Boiler, Horizontally Opposed Wall Firing, Dry Bottom Field Erected Watertube, Coal	0.009	0.077	98.43
91. Industrial Boiler, Front Wall Fired Dry Bottom Field Erected Watertube, Coal	0.009	0.077	98.51
92. Industrial Boiler, Opposed Wall Firing Field Erected Watertube, Process Gas	0.009	0.077	98.59
93. Industrial Boiler, Wall Fired Packaged Watertube, Coal	0.009	0.077	98.66
94. Commercial Boiler, Firetube, Stoker, Miscellaneous, HRT, Coal	0.009	0.077	98.74
95. Utility Boiler, Horizontally Opposed Wall Firing, Wet Bottom, Lignite Coal	0.008	0.069	98.81
96. Utility Boiler, Front Wall Fired, Wet Bottom, Lignite Coal	0.008	0.069	98.88
97. Commercial Boilers, Firetube, Miscellaneous, Residual Oil	0.0075	0.064	98.94
98. Industrial Boiler, Stoker, Miscellaneous, Packaged Watertube, Coal	0.007	0.060	99.00
99. Utility Boiler, Tangential Firing, Distillate Oil	0.007	0.060	99.06
100. Industrial Boiler, Bent Tube, Wall Fired Field Erected Watertube, Distillate Oil	0.007	0.060	99.12
101. Industrial Boiler, Wall Fired Packaged Watertube, Process Gas	0.007	0.060	99.18
102. Industrial Boiler, Front Wall Fired Field Erected Watertube, Process Gas	0.007	0.060	99.24
103. Commercial Boiler, Firetube, Miscellaneous, Gas	0.006	0.051	99.29
104. Industrial Boiler, Firetube Wall Fired Packaged Firebox, Distillate Oil	0.006	0.051	99.34
105. Process Heating, Coke Oven Underfire	0.0059	0.051	99.39
106. Process Heating, Heating, Annealing Ovens	0.0056	0.048	99.44
107. Industrial Boiler, Firetube, Stoker, Underfeed, Packaged HRT, Coal	0.005	0.043	99.49

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
108.	Industrial Boiler, Tangential Firing Field Erected Watertube, Process Gas	0.004	0.034	99.52
109.	Utility Boiler, Horizontally Opposed Wall Firing, Dry Bottom, Lignite Coal	0.004	0.034	99.55
110.	Utility Boiler, Front Wall Fired, Dry Bottom, Lignite Coal	0.004	0.034	99.59
111.	Commercial Boiler, Firetube, Miscellaneous, Distillate Oil	0.0031	0.027	99.61
112.	Industrial Boiler, Front Wall Firing, Wet Bottom Field Erected Watertube, Coal	0.003	0.026	99.64
113.	Industrial Boiler, Horizontally Opposed Wall Firing, Wet Bottom Field Erected Watertube, Coal	0.003	0.026	99.67
114.	Industrial Boiler, Firetube Wall Fired Packaged HRT, Distillate Oil	0.003	0.026	99.69
115.	Commercial Boiler, Watertube Wall Fired Coil, Residual Oil	0.003	0.026	99.72
116.	Commercial Boiler, Watertube, Miscellaneous, Residual Oil	0.003	0.026	99.74
117.	Commercial Boiler, Watertube Wall Fired Coil, Gas	0.0024	0.021	99.77
118.	Commercial Boiler, Watertube, Miscellaneous, Gas	0.0024	0.021	99.79
119.	Industrial Boiler, Vertical Firing Field Erected Watertube, Coal	0.002	0.017	99.80
120.	Industrial Boiler, Firetube Stoker, Overfeed Packaged Firebox, Coal	0.002	0.017	99.82
121.	Industrial Boiler, Firetube, Stoker, Spreader, Packaged Firebox, Coal	0.002	0.017	99.84
122.	Commercial Boiler, Firetube, Miscellaneous, Coal	0.002	0.017	99.85
123.	Industrial Boiler, Bent Tube Wall Fired Field Erected Watertube, Process Gas	0.002	0.017	99.87
124.	Commercial Boiler, Watertube Wall Fired Firebox, Residual Oil	0.002	0.017	99.89
125.	Process Heating, Brick Curing Gas	0.0014	0.012	99.9
126.	Commercial Boiler, Watertube Wall Fired Coil, Distillate Oil	0.001	0.009	99.91
127.	Commercial Boiler, Watertube, Other, Distillate Oil	0.001	0.009	99.92

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
128.	Commercial Boiler, Watertube Wall Fired Firebox, Gas	0.001	0.009	99.93
129.	Utility Boiler, Vertical Firing, Lignite Coal	0.001	0.009	99.94
130.	Utility Boiler, Cyclone, Distillate Oil	0.001	0.009	99.95
131.	Industrial Boiler, Firetube Stoker, Spreader, Packaged HRT, Coal	0.001	0.009	99.95
132.	Industrial Boiler, Firetube Stoker, Overfeed, Packaged HRT, Coal	0.001	0.009	99.96
133.	Industrial Boiler, Firetube Wall Fired Packaged Firebox, Process Gas	0.001	0.009	99.97
134.	Industrial Boiler, Firetube Wall Fired Packaged Scotch, Process Gas	0.001	0.009	99.98
135.	Commercial Boiler, Watertube, Wall Fired Firebox, Distillate Oil	0.0006	0.005	99.99
136.	Process Heating, Brick Curing, Oil	0.0003	0.003	99.99
137.	Process Heating, Brick Curing, Coal	0.0003	0.003	100
	Total Controllable	11.6648	100	100

UNRANKED SOURCES – EMISSION NEGLIGIBLE OR NOT AVAILABLE

Utility Boiler, Tangentially Fired Wet Bottom, Coal Fired
Utility Boiler, Mixed Fuel Fired
Utility Boiler, Gas Fired Cyclone
Industrial Boiler, Mixed Fuel Fired
Industrial Boiler, Liquid Waste Fired
Industrial Boiler, Solid Waste Fired
Industrial Boiler, Sub-Bituminous or Lignite Fired
Boilers, Anthracite Coal Fired
Boilers, Synthetic Fuel From Coal, Low Btu Gas, SRC
Fluidized Bed Boilers
Stationary IC Engines, Gasoline Fired
Combined Gas/Steam Turbine Cycles
MHD Power Generation
Residential Units, Coal Fired
Residential Units, Bottled Gas
All Wood Fired Equipment
Minor Industrial Process Equipment

2 OF 2

PB

246 750

1.0
4.5
5.0
5.6
6.3
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8.0
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10
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3.2
3.6
4.0
2.5
2.2
2.0
1.1
1.8
1.25
1.4
1.6

gas cleanup are not presented since that technique is not considered a viable means of NO_x reduction for stationary units.

The most recent cost studies on NO_x controls for gas turbines have been performed by Aerospace (Reference 4-14) and EPA (Reference 4-16). In the absense of any nationwide limitation on NO_x emission levels, very little data exist relative to actual costs. The smaller capacity gas turbines, as was previously cited, may very well be capable of NO_x levels below proposed standards without the installation of wet controls, whereas the larger units almost universally will require either water or steam injection and possibly some minor combustor modifications.

As input to the Aerospace study, San Diego Gas and Electric provided their investment costs for water injection retrofit to three units as presented in Table 4-12. These costs are based on a baseline investment cost of an uncontrolled simple cycle turbine of about $80 - 100/Kw and an operational cost of 20 - 24 mils/kw hour for intermediate loads (6000 hours per year; fuel costs of 80¢/10^6Btu). In this example, the incremental investment costs for water injection can be as high as 10% for the 20 MW plant and as low as 6% for the 49 and 81 MW plants. Investment and operating costs for steam injection are generally accepted to be higher than water injection unless superheated steam is available on-site. A comparison of investment and operating costs for both water and steam injection as a function of turbine size is presented in Table 4-13. Wet control costs are seen to be prohibitive for the turbines of smaller size but, in general, wet controls will not be required by these units to effectively reduce emission levels below proposed standards. Noting that operating costs decrease as a function of both turbine size and load factor, it is conceivable that the base loading with a 65 MW unit operational cost could be as low as 2.5%.

A more extensive breakdown of the costs for wet and dry controls has been assembled by EPA in support of proposed emission standards. Table 4-14 presents the cost of NO_x control for small gas turbines. The table illustrates the cost of dry controls for two units, a 350 hp and a 3500 hp unit, and the cost of wet controls for the 3500 hp turbine. Although it is assumed that most of the smaller capacity units will be sufficiently controlled by dry control to exclude the use of wet controls, it is not certain that the larger capacity small turbines (50 M Btu) will not require water or steam injection; therefore, estimates are included for both methods of control. Operating costs vary from 17% for the standby 350 hp turbine to a low of 1.3% for the 8000 hr/year 3500 hp dry controlled unit. Table 4-15 presents similar cost estimates for large gas turbines equipped with water injection. Again these are costs provided by San Diego Gas & Electric to EPA. Costs here do not include on - site personnel since controls were designed to operate automatically on the generally unattended turbine.

TABLE 4-12. WATER INJECTION INVESTMENT COST
(SAN DIEGO GAS AND ELECTRIC)

Control System	Gas Turbine Size		
	20 MW	49 MW	81 MW
Combustor modifications including water injection nozzles	$1.00/kw	$0.86/kw	$1.04/kw
Water injection pumps and water regulation system	$3.54/kw	$2.88/kw	$3.10/kw
Associated piping and water storage facilities	$1.72/kw	$1.05/kw	$0.87/kw
Water treatment equipment	$0.90/kw	$0.47/kw	$0.47/kw
General expenses including engineering, administration, testing taxes	$1.15/kw	$0.82/kw	$0.57/kw
TOTAL	$8.31/kw	$6.07/kw	$6.05/kw

TABLE 4-13. WATER/STEAM INJECTION COST AS A
FUNCTION OF POWER PLANT SIZE

MW Output	Investment Cost, Percent Baseline		*Operational Cost, Percent Baseline	
	Water	Steam	Water	Steam
0.26 (350 hp)	100.0	150.0	55.0	165
2.90 (3900 hp)	18.0	24.0	6.5	32
20.00	10.0	12.0	6.0	–
33.00	7.3	10.6	5.7	–
65.00	7.3	10.6	5.7	–

*For peaking gas turbine, 1000 hour/year

TABLE 4-14. 1974 ESTIMATED COSTS OF NO_x CONTROLS FOR SMALL GAS TURBINES (REFERENCE 4-16)

Size, hp	350		3,500		3,500	
Purchase cost (PC), uncontrolled	8,800		110,000		110,000	
Total installed cost (TIC), 1.3xPC	11,400		143,000		143,000	
Total capital investment (TCI), 1.25XTIC	14,300		178,800		178,800	
Control increment, percent	Dry 20		Dry 12		Wet 25	
TCI, controlled	17,200		200,000		224,000	
Unit investment, controlled, $/hp	49		57		64	
Heat rate, Btu/hph	12,000		11,000		11,000	
Equivalent hours duty per year	100[a]	8,000[b]	100	8,000	100	8,000
Fuel @ $0.91/MBtu[c]	380	30,600	3,500	280,300	3,500	280,300
Fixed charges, uncontrolled[d]	2,600	2,600	32,200	32,200	32,200	32,200
Total annual cost, uncontrolled	3,000	33,200	35,700	312,500	35,700	312,500
Utilities[e]	--	--	--	--	12	1,000
Incremental fixed charges[d]	520	520	3,900	3,900	8,000	8,000
Total annual cost, controlled	3,500	33,700	39,600	316,400	43,700	321,500
Control cost, percent	17	1.6	11	1.3	22	2.9

Notes:

[a] As in emergency service, including readiness tests

[b] As in pipeline service

[c] In the pipeline application, fuel from the line would be much less expensive

[d] Carrying charges 17 percent, maintenance 1 percent

[e] Raw water, regeneration chemicals, and power together assumed $1/1000 gallon

TABLE 4-15. 1974 ESTIMATED COSTS OF WET NO_x CONTROLS FOR LARGE GAS TURBINES (REFERENCE 4-16)

Size, MW	25			4x65		
Capital costs in thousands of dollars:						
Total capital investment (TCI)[a], uncontrolled		2800			26000	
Equivalent hours duty per year	8000	1000	1000	4000	1000	1000
Water/fuel ratio	0.5	0.5	0.8	0.5	0.5	0.8
Control increment,[b] percent	10.0	8.5	9.5	3.9	3.5	3.9
TCI, controlled	3120	3040	3070	27000	26900	27000
Unit investment, controlled, $/kw	125	121	123	104	103	104
Annualized costs in thousands of dollars:						
Heat rate, Btu/kwh		12400			11700	
Fuel @ $0.91/MBtu	2260	282	282	11070	2770	2770
Fixed charges, uncontrolled[d]	504	504	504	4670	4670	4670
Total annual cost, uncontrolled	2764	786	786	15740	7440	7440
Utilities[e]	9	1	2	40	10	16
Incremental fixed charges	57	43	49	180	160	180
Total annual cost, controlled	2830	830	837	15960	7610	7640
Incremental annual cost, percent	2.3	5.6	6.5	1.4	2.3	2.6

Notes: [a] Applying to the 25 MW case, the 1970 Federal Power Survey datum of $85/kw, escalating from 1968 to 1974 at 5 percent compounded, and assuming a weak economy of scale for the larger case.

[b] Wet controls include an injection system sized for peak injection rate.

[c] In the 8000-hour case representing a pipeline compressor, fuel from the line would be much less expensive.

[d] Carrying charges 17 percent, maintenance 1 percent.

[e] Raw water, regeneration chemicals, power and sewerage together at $1/1000 gallons.

A cost effectiveness summary is presented in Table 4-16 and illustrates the relationship between control costs and resultant NO_x levels. Note that using the given reduction assumptions, the 3500 hp unit with dry controls only would not meet the present San Diego County standards of 42 and 75 ppm NO_x @15 percent oxygen for gas and liquid fuels, respectively.

In summary, the primary economic considerations in controlling NO_x from gas turbines are:

- Wet controls are by far the most expensive means of NO_x control, but they are presently the only adequate means for the large units (> 50M Btu).
- Dry controls are the most desirable in terms of cost but alone are applicable only to the smaller units (< 50M Btu). These controls may not be sufficient for those units approaching 50M Btu in size.
- Incremental operating costs decrease as loading factor and size increase. Increments as low as 1.3% are shown.

4.4 COMMERCIAL AND RESIDENTIAL HEATING

This section discusses the economic considerations in reducing bulk emissions from both commercial and residential space heating units for the three presently applicable strategies presented in Section 3.1.4:

- Tuning
- Burner replacement
- Unit replacement

A scan of several service organizations across the country indicates that the tuning procedure consists of cleaning, leak detection, sealing, and flame adjustment using the "eyeball" technique. None of the service companies contacted offered the instrumented tuning described in Section 3.1.4, but some were aware of this method and believed it would be available in the near future at a substantially higher cost than the present service. The presently available tuning procedure costs a minimum of $45 for the average residential unit while cost increases with unit size, necessary replacement parts, and abnormal time requirements.

Burner replacement in residential units is considered an uncommon practice by servicemen since new burner costs, installation labor cost and furnace life expectation on the order of 10 to 15 years make burner replacement very costly. New burners cost a minimum of $35, and when added to total installation costs (labor and adjustment) at approximately $20 per hour for two hours minimum, the burner replacement costs at least $75. Burner replacement in some cases may not be effective in reducing emissions and, in fact, could possible increase pollutant production if furnace-burner compatibility is not determined prior to installation. This amount would not seem to be cost effective for residential units, but the emergence of

TABLE 4-16. COST-EFFECTIVENESS SUMMARY (REFERENCE 4-16)

Scale	Fuel	NO$_X$ Concentration, ppmv			Method	Incremental Unit Cost
		Uncontrolled		Controlled[a]		
350 hp	Gas	60		42	Dry	1.6% in pumping service
	Oil	90		68	Dry	
3500 hp	Gas	70		49	Dry	1.3% in pumping service
	Oil	110		83	Dry	
3500 hp	Oil	110		37[b]	Wet	2.9% in pumping service
			W/F = 0.5	0.8		W/F = 0.5
25 MW	Gas	160	54	36	Wet	5.6% to 6.5% in peaking service
	Oil	220	74	50	Wet	
4x65 MW	Gas	200	67	45	Wet	2.3% to 2.6% in peaking service
	Oil	260	88	59	Wet	

Notes:

[a] Assuming 25 percent reduction for oil, 30 percent for gas, with dry controls.
Assuming 25 percent, attributable to the dry controls incorporated with wet controls, compounded by further reductions of 55 percent at W/F = 0.5, 70 percent at W/F = 0.8.

[b] At W/F = 0.5

new low emission burners and the promulgation of NO_x emission restrictions could make this the most attractive control alternative. Commercial burner replacement is a more common practice owing to the characteristically higher unit costs and the longer life expectancies.

Unit replacement strictly for emission control is not cost effective; however, estimates for replacement are included for units in poor condition or units in need of extensive repair. Table 4-17 provides estimates for residential and commercial unit replacement costs.

4.5 ADDITIONAL COST DATA REQUIREMENTS

While this report has attempted to present general cost estimates of NO_x control techniques for the primary stationary source equipment categories, there exists a further requirement for the collection of a substantially more extensive data base from which estimates can be made. The utility boiler category comprises the bulk of published cost information since this equipment type bore the initial thrust of NO_x control technology. Only recently have the remaining equipment categories been subject to pilot or full scale testing, and therefore extensive cost data is not yet available. This section indicates the equipment categories and which equipment types therein require further generation of economic data for future NO_x control cost estimates. An important point to remember is that all published economic data no matter how extensively presented, will only provide general guidelines to those decision makers considering the implementation of the various control techniques. Actual costs must be determined on a unit-by-unit basis.

4.5.1 Utility Boilers

A relatively large quantity of data on the economics of NO_x control technology presently exists for utility boilers. However, this information is generally diffuse in nature since it is derived from many sources. In addition, much of the potentially valuable cost figures are proprietary, residing with individual electric utility companies. Further insight into the cost-effectiveness of modifying a utility boiler combustion process will be gained by satisfying the following requirements:

- Compilation of more complete information on the costs of installing a flue gas recirculation system on "typical" existing units for all three conventional fuels.
- Acquisition of additional data on the installed equipment costs of off-stoichiometric combustion techniques.
- Acquisition of information on all aspects of differential operating costs associated with each control technique.
- Preparation of "case studies" of individual utility companies that have used combustion modification techniques in order to give a profile of user experiences.

TABLE 4-17. TYPICAL COSTS OF GAS FIRED SPACE HEATING UNITS (REFERENCE 4-17)

Capacity	Floor Furnaces	Forced Air*	Space Heaters
35,000 Btu	225-245	-	380 suspended
65,000	270-290	395-450	450 suspended
100,000	-	460-530	925 floor
300,000	-	670-780	2400 floor
750,000	-	-	5150 floor

*Add 15% for oil or coal firing.

4.5.2 Industrial Boilers

As for most of the other equipment types, there is a general lack of cost data associated with combustion modification techniques implemented on industrial-size boilers. It is anticipated that this data base will be augmented by ongoing EPA-sponsored boiler field tests. At this time, however, the information gaps are large. In order to present a more complete picture of the feasibility of combustion modification techniques to the boiler operator and/or owner, the following cost data must be generated:

- For multiburner boilers, the installed equipment costs of off-stoichiometric combustion techniques and the applicability and installed equipment costs of a flue gas recirculation system
- The installed equipment costs of low excess air firing on all boiler types
- Differential operating costs (e.g., increased fuel consumption) of all techniques implemented on all applicable boiler types

4.5.3 Internal Combustion Engines

This equipment sector consists of both reciprocating IC engines and gas turbines. In contrast to reciprocating engines which have such a diversity of equipment combinations, gas turbine equipment combinations are relatively uncomplicated. In view of this difference, reciprocating engine economics are generally presented in terms of engine capacity and/or fuel where gas turbines are discussed by equipment type and/or capacity.

4.5.3.1 Reciprocating Engines

Further cost analyses for reciprocating IC engines are recommended in the following capacity/fuel combinations:

- DEMA (> 100 hp/cyl)
    - present cost estimates derive from the manufacturers experimental in-house units; future data must be compiled from field units particularly regarding cost and control tradeoff in the retrofit unit
    - Cost data must be generated first for specific controls and then for various control combinations and their relationship to control effectiveness
- Mid-Power Engines — almost no cost data for stationary units in this capacity range exists at the present time
    - the bulk of the cost information deals with diesel fueled truck applications however the contrasting load cycles and less restrictive packaging requirements of stationary installations do not lend to accurate cost data transfer. Data must be generated from stationary units.

  - gas fueled units require the entire cost analyses spectrum as essentially no data exist for stationary installations.
  - individual and combinations of control cost data versus control effectiveness must be determined for all equipment categories.
- Small Gasoline Engines — here again, little data exist for stationary application and cost transfer from mobile units is not effective. Essentially all economic aspects of control costs must be investigated in this capacity/fuel range.

4.5.3.2 Gas Turbines

Gas turbine cost data, although more complete than those of reciprocating engines, is lacking in the following areas:

- Utility Applications
  - specific cost data exist on wet control techniques from an actual on-site application but typical costs cannot be assumed from one installation. As wet controls come into more common usage, detailed cost analyses must be undertaken..
  - No on-site cost data exist for dry controls in utility turbines.
- Equipment Classifications
  - open cycle turbines encompass the majority of any existing economic data. Further information is required for on-site wet controls and a complete cost analysis is needed for dry controls as they emerge.
  - Regenerative cycle turbines again require economic data covering the entire range of applicable controls.
  - Combined cycle installations are just recently gaining in popularity and consequently cost information is scarce.
  - As wet and dry controls become more common, control cost-control effectiveness relationships must be determined for all classes of equipment.

4.5.4 Space Heating

The space heating sector cost data base for NO_x control techniques suffers from lack of control implementation in the commercial heating segment and absence of viable NO_x control techniques in the residential segment.

- Commercial Space Heating
  - some cost information from industrial boilers may be applicable on the upper capacity range but contrasting duty cycles introduce uncertainty in the cost data transfer.

  - detailed economic analyses are recommended for all aspects of commercial space heating NO_x control.

- Residential Space Heating — the present control strategy within the sector is the overall reduction of unit emissions since compatible NO_x controls remain to be developed. Cost analyses must be performed for the present strategies until specific NO_x controls emerge.

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APPENDIX A

A numerical ranking by NO_x production is presented for the 137 equipment/fuel combinations as discussed in Section 2.1. Estimates are believed to be fairly accurate for the top 30 or so sources which comprise greater than 80 percent of the total emissions. The proportionate error undoubtedly increases whicle progressing to the minor sources so that the numerical ranking of the very minor sources is qualitative at best.

The sources at the end of the list were not given numerical rankings because they are regarded as negligible, or emission data was not available. Mixed fuel firing is included in the not available category even though its use is prevalent. This is because fuel consumption data is reported in terms of constituent fuel only without regard to whether it is fired singly or mixed with another fuel. A number of other equipment/fuel types could be listed in the negligible category.

It is emphasized that a high source placement in the emission rankings does not necessarily mean that individual units are high emitters. Rather, the sources may have relatively low emission factors, but a high placement due to the large number of installed units of that type. Such is the case, for example, for tangential coal fired utility boilers. These units are of a fairly standard design and were not subdivided into design types, as was necessary for wall fired utility boilers. It is also emphasized that sources on this list are confined to controllable types of processes and exclude such things as forest fires and open burning.

Rankings are presented in the following Table A-1.

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE

Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
1. IC Engines, Spark Ignition, Gas Fired	1.873	16.06	
2. Utility Boiler, Tangential Firing, Bituminous Coal	1.388	11.90	27.96
3. Utility Boiler, Cyclone Firing, Bituminous Coal	0.730	6.26	34.22
4. Utility Boiler, Horizontally Opposed Wall Firing, Gas	0.568	4.87	39.09
5. Utility Boiler, Horizontally Opposed Wall Firing, Dry Bottom, Bituminous Coal	0.412	3.53	42.62
6. Utility Boiler, Front Wall Firing, Dry Bottom, Bituminous Coal	0.412	3.53	46.15
7. Utility Boiler, Front Wall Firing, Gas	0.393	3.37	49.52
8. IC Engine, Diesel, Oil and Dual Fuels	0.316	2.71	52.23
9. Utility Boiler, Horizontally Opposed Wall Firing, Wet Bottom Bituminous Coal	0.306	2.62	54.85
10. Utility Boiler, Front Wall Firing, Wet Bottom, Bituminous Coal	0.302	2.59	57.44
11. Utility Boiler, Horizontally Opposed Wall Firing, Residual Oil	0.271	2.32	59.76
12. Utility Boiler, Front Wall Firing, Residual Oil	0.271	2.32	62.08
13. Industrial Boiler, Bent Tube Wall Fired Packaged Watertube, Residual Oil	0.2064	1.77	63.85
14. Industrial Boiler, Firetube Wall Fired Packaged Scotch, Residual Oil	0.1924	1.65	65.50
15. Utility Boiler, Tangential Firing, Residual Oil	0.177	1.52	67.02
16. Gas Turbines, Gas Fired	0.172	1.47	68.49
17. Industrial Boiler, Front Wall Firing Field Erected Watertube, Residual Oil	0.165	1.41	69.90
18. Industrial Boiler, Horizontally Opposed Wall Firing Field Erected Watertube, Residual Oil	0.165	1.41	71.31
19. Utility Boiler, Tangential Firing, Gas	0.153	1.31	72.62
20. Industrial Boiler, Bent Tube Wall Fired Packaged Watertube, Gas	0.139	1.19	73.81
21. Industrial Boiler, Stoker, Spreader Field Erected Watertube, Coal	0.136	1.17	74.98
22. Utility Boiler, Vertical Firing, Bituminous Coal	0.127	1.09	76.07
23. Gas Turbine, Oil Fired	0.119	1.02	77.09

Table A-1. ESTIMATED 1972 NO_X EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_X EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
24. Nitric Acid Production	0.11	0.94	78.03
25. Process Heating, Glass Manufacture	0.11	0.94	78.97
26. Residential Heating, Hot Air Furnace, Distillate Oil	0.107	0.92	78.89
27. Residential Heating, Hot Air Furnace, Gas	0.106	0.91	80.80
28. Industrial Boiler, Tangential Firing, Field Erected Watertube, Residual Oil	0.106	0.91	81.71
29. Petroleum Catalytic Crackers (FCC)	0.099	0.85	82.56
30. Residential Heating, Steam or Hot Water, Distillate Oil	0.097	0.83	83.39
31. Industrial Boiler, Horizontally Opposed Wall Firing Field Erected Watertube, Gas	0.087	0.75	84.14
32. Industrial Boiler, Bent Tube Wall Fired Field Erected Watertube, Residual Oil	0.086	0.74	84.88
33. Industrial Boiler, Stoker, Underfeed, Field Erected Watertube, Coal	0.077	0.66	85.54
34. Industrial Boiler, Firetube Wall Fired Packaged Fire Box, Residual Oil	0.076	0.65	86.19
35. Industrial Boiler, Stoker, Underfeed, Packaged Watertube, Coal	0.067	0.57	86.76
36. Industrial Boiler, Front Wall Firing, Field Erected Watertube, Gas	0.059	0.51	87.27
37. Process Heating, Cement Kilns, Coal Fired	0.055	0.475	87.75
38. Process Heating, Cement Kilns, Gas Fired	0.047	0.40	88.15
39. Commercial Boiler, Firetube Wall Fired Packaged Scotch, Residual Oil	0.0452	0.39	88.54
40. Commercial Boiler, Firetube Wall Fired Packaged Firebox, Residual Oil	0.0452	0.39	88.93
41. Industrial Boiler, Bent Tube Wall Fired Field Erected Watertube, Gas	0.045	0.39	89.32
42. Industrial Boiler, Firetube Wall Fired Packaged Scotch, Gas	0.044	0.38	89.70
43. Industrial Boiler, Stoker Spreader Packaged Watertube, Coal	0.043	0.37	90.07
44. Residential Heating, Steam or Hot Water, Gas	0.040	0.34	90.41

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
45. Industrial Boiler, Firetube Wall Fired Packaged HRT, Residual Oil	0.040	0.34	90.75
46. Industrial Boiler, Firetube Wall Fired Packaged Firebox, Gas	0.038	0.33	91.07
47. Utility Boiler, Stoker, Spreader, Coal	0.037	0.32	91.40
48. Industrial Boiler, Stoker, Overfeed, Field Erected Watertube, Coal	0.037	0.32	91.72
49. Commercial Boiler, Firetube Wall Fired Packaged Scotch, Gas	0.036	0.31	92.03
50. Commercial Boiler, Firetube Wall Fired Packaged Firebox, Gas	0.036	0.31	92.34
51. Industrial Boiler, Tangential Firing Field Erected Watertube Gas	0.032	0.27	92.61
52. Industrial Boiler, Tangential Firing Field Erected Watertube, Coal	0.030	0.26	92.87
53. Residential Heating, Room Heater With Flue, Gas	0.028	0.24	93.11
54. Explosive Manufacture	0.028	0.24	93.35
55. Industrial Boiler, Cyclone Field Erected Watertube, Coal	0.028	0.24	93.59
56. Residential Heating, Floor, Wall or Pipeless Heaters, Gas	0.027	0.23	93.82
57. Iron and Steel Industry, Open Hearth Furnace	0.025	0.21	94.03
58. Iron and Steel Industry, Sintering	0.024	0.21	94.24
59. Residential Heating, Room Heater With Flue, Distillate Oil	0.024	0.21	94.45
60. Incineration, Industrial	0.023	0.20	94.65
61. Commercial Boiler, Firetube, Wall Fired Cast Iron, Residual Oil	0.0226	0.19	94.84
62. Commercial Boiler, Firetube Wall Fired HRT, Residual Oil	0.0226	0.19	95.03
63. Industrial Boiler, Firetube Wall Fired Packaged HRT, Gas	0.020	0.17	95.20
64. Utility Boiler, Cyclone, Residual Oil	0.019	0.16	95.36
65. Commercial Boiler, Firetube Wall Fired Packaged Scotch, Distillate Oil	0.0184	0.16	95.52

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
66. Commercial Boiler, Firetube Wall Fired Firebox, Distillate Oil	0.0184	0.16	95.68
67. Industrial Boiler, Stoker General, Field Erected Watertube, Coal	0.018	0.15	95.83
68. Commercial Boiler, Firetube Wall Fired HRT, Gas	0.018	0.15	95.98
69. Incineration, Municipal	0.018	0.15	96.13
70. Commercial Boiler, Wall Fired Cast Iron, Gas	0.018	0.15	96.28
71. Commercial Boiler, Firetube, Stoker, Miscellaneous, Firebox, Coal	0.018	0.15	96.43
72. Process Heating, Cement Kilns, Oil	0.0165	0.14	96.57
73. Utility Boiler, Stoker Underfeed, Coal	0.016	0.14	96.71
74. Residential Heating, Floor, Wall or Pipeless Heater, Distillate Oil	0.016	0.14	96.85
75. Industrial Boiler, Stoker, Overfeed, Packaged Watertube, Coal	0.016	0.14	96.99
76. Industrial Boiler, Firetube Wall Fired Packaged Scotch, Distillate Oil	0.0156	0.13	97.12
77. Industrial Boiler, Wall Fired Packaged Watertube, Distillate OIl	0.0156	0.13	97.25
78. Utility Boiler, Tangential Firing, Lignite Coal	0.014	0.12	97.37
79. Industrial Boiler, Cyclone Field Erected Watertube, Residual OIl	0.014	0.12	97.49
80. Sulfuric Acid Production	0.011	0.094	97.58
81. Utility Boiler, Horizontally Opposed Wall Firing, Distillate Oil	0.011	0.094	97.67
82. Utility Boiler, Front Wall Firing, Distillate Oil	0.011	0.094	97.76
83. Residential Heating, Room Heater Without Flue, Gas	0.011	0.094	97.86
84. Residential Heating, Room Heater Without Flue, Distillate Oil	0.010	0.086	97.95
85. Utility Boiler, Vertical Firing, Anthracite Coal	0.010	0.086	98.03
86. Industrial Boiler, Firetube Stoker Underfeed Packaged Firebox, Coal	0.010	0.086	98.12
87. Commercial Boiler, Firetube, Wall Fired HRT, Distillate Oil	0.0092	0.079	98.20

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
88.	Commercial Boiler, Wall Fired Cast Iron, Distillate Oil	0.0092	0.079	98.28
89.	Utility Boiler, Cyclone, Lignite Coal	0.009	0.077	98.35
90.	Industrial Boiler, Horizontally Opposed Wall Firing, Dry Bottom Field Erected Watertube, Coal	0.009	0.077	98.43
91.	Industrial Boiler, Front Wall Fired Dry Bottom Field Erected Watertube, Coal	0.009	0.077	98.51
92.	Industrial Boiler, Opposed Wall Firing Field Erected Watertube, Process Gas	0.009	0.077	98.59
93.	Industrial Boiler, Wall Fired Packaged Watertube, Coal	0.009	0.077	98.66
94.	Commercial Boiler, Firetube, Stoker, Miscellaneous, HRT, Coal	0.009	0.077	98.74
95.	Utility Boiler, Horizontally Opposed Wall Firing, Wet Bottom, Lignite Coal	0.008	0.069	98.81
96.	Utility Boiler, Front Wall Fired, Wet Bottom, Lignite Coal	0.008	0.069	98.88
97.	Commercial Boilers, Firetube, Miscellaneous, Residual Oil	0.0075	0.064	98.94
98.	Industrial Boiler, Stoker, Miscellaneous, Packaged Watertube, Coal	0.007	0.060	99.00
99.	Utility Boiler, Tangential Firing, Distillate Oil	0.007	0.060	99.06
100.	Industrial Boiler, Bent Tube, Wall Fired Field Erected Watertube, Distillate Oil	0.007	0.060	99.12
101.	Industrial Boiler, Wall Fired Packaged Watertube, Process Gas	0.007	0.060	99.18
102.	Industrial Boiler, Front Wall Fired Field Erected Watertube, Process Gas	0.007	0.060	99.24
103.	Commercial Boiler, Firetube, Miscellaneous, Gas	0.006	0.051	99.29
104.	Industrial Boiler, Firetube Wall Fired Packaged Firebox, Distillate Oil	0.006	0.051	99.34
105.	Process Heating, Coke Oven Underfire	0.0059	0.051	99.39
106.	Process Heating, Heating, Annealing Ovens	0.0056	0.048	99.44
107.	Industrial Boiler, Firetube, Stoker, Underfeed, Packaged HRT, Coal	0.005	0.043	99.49

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
108.	Industrial Boiler, Tangential Firing Field Erected Watertube, Process Gas	0.004	0.034	99.52
109.	Utility Boiler, Horizontally Opposed Wall Firing, Dry Bottom, Lignite Coal	0.004	0.034	99.55
110.	Utility Boiler, Front Wall Fired, Dry Bottom, Lignite Coal	0.004	0.034	99.59
111.	Commercial Boiler, Firetube, Miscellaneous, Distillate Oil	0.0031	0.027	99.61
112.	Industrial Boiler, Front Wall Firing, Wet Bottom Field Erected Watertube, Coal	0.003	0.026	99.64
113.	Industrial Boiler, Horizontally Opposed Wall Firing, Wet Bottom Field Erected Watertube, Coal	0.003	0.026	99.67
114.	Industrial Boiler, Firetube Wall Fired Packaged HRT, Distillate Oil	0.003	0.026	99.69
115.	Commercial Boiler, Watertube Wall Fired Coil, Residual Oil	0.003	0.026	99.72
116.	Commercial Boiler, Watertube, Miscellaneous, Residual Oil	0.003	0.026	99.74
117.	Commercial Boiler, Watertube Wall Fired Coil, Gas	0.0024	0.021	99.77
118.	Commercial Boiler, Watertube, Miscellaneous, Gas	0.0024	0.021	99.79
119.	Industrial Boiler, Vertical Firing Field Erected Watertube, Coal	0.002	0.017	99.80
120.	Industrial Boiler, Firetube Stoker, Overfeed Packaged Firebox, Coal	0.002	0.017	99.82
121.	Industrial Boiler, Firetube, Stoker, Spreader, Packaged Firebox, Coal	0.002	0.017	99.84
122.	Commercial Boiler, Firetube, Miscellaneous, Coal	0.002	0.017	99.85
123.	Industrial Boiler, Bent Tube Wall Fired Field Erected Watertube, Process Gas	0.002	0.017	99.87
124.	Commercial Boiler, Watertube Wall Fired Firebox, Residual Oil	0.002	0.017	99.89
125.	Process Heating, Brick Curing Gas	0.0014	0.012	99.9
126.	Commercial Boiler, Watertube Wall Fired Coil, Distillate Oil	0.001	0.009	99.91
127.	Commercial Boiler, Watertube, Other, Distillate Oil	0.001	0.009	99.92

Table A-1. ESTIMATED 1972 NO_x EMISSIONS FROM STATIONARY SOURCES – RANKING OF NO_x EMISSIONS BY EQUIPMENT TYPE AND FIRING TYPE (Continued)

	Sector/Equipment Type/Fuel	Est. TPY x 10^6	Percent of Total	Cumulative Percent
128.	Commercial Boiler, Watertube Wall Fired Firebox, Gas	0.001	0.009	99.93
129.	Utility Boiler, Vertical Firing, Lignite Coal	0.001	0.009	99.94
130.	Utility Boiler, Cyclone, Distillate Oil	0.001	0.009	99.95
131.	Industrial Boiler, Firetube Stoker, Spreader, Packaged HRT, Coal	0.001	0.009	99.95
132.	Industrial Boiler, Firetube Stoker, Overfeed, Packaged HRT, Coal	0.001	0.009	99.96
133.	Industrial Boiler, Firetube Wall Fired Packaged Firebox, Process Gas	0.001	0.009	99.97
134.	Industrial Boiler, Firetube Wall Fired Packaged Scotch, Process Gas	0.001	0.009	99.98
135.	Commercial Boiler, Watertube, Wall Fired Firebox, Distillate Oil	0.0006	0.005	99.99
136.	Process Heating, Brick Curing, Oil	0.0003	0.003	99.99
137.	Process Heating, Brick Curing, Coal	0.0003	0.003	100
	Total Controllable	11.6648	100	100

UNRANKED SOURCES – EMISSION NEGLIGIBLE OR NOT AVAILABLE

Utility Boiler, Tangentially Fired Wet Bottom, Coal Fired
Utility Boiler, Mixed Fuel Fired
Utility Boiler, Gas Fired Cyclone
Industrial Boiler, Mixed Fuel Fired
Industrial Boiler, Liquid Waste Fired
Industrial Boiler, Solid Waste Fired
Industrial Boiler, Sub-Bituminous or Lignite Fired
Boilers, Anthracite Coal Fired
Boilers, Synthetic Fuel From Coal, Low Btu Gas, SRC
Fluidized Bed Boilers
Stationary IC Engines, Gasoline Fired
Combined Gas/Steam Turbine Cycles
MHD Power Generation
Residential Units, Coal Fired
Residential Units, Bottled Gas
All Wood Fired Equipment
Minor Industrial Process Equipment